National Energy Board

CANADA

Office national de l'énergie

File No: 7500-A000-2

3 September 1992

To: All Interested Parties

Re: Export Impact Assessment

The Export Impact Assessment (EIA) forms one component of the public hearing component of the Market-Based Procedure (MBP), the method by which the Board assesses applications for long-term natural gas export licences. The intent of the EIA is to allow the Board to determine whether a proposed export is likely to cause Canadians difficulty in meeting their energy requirements at fair market prices.

When the MBP was implemented in 1987, the Board initially required licence applicants to file their own EIA studies. However, in 1989, pursuant to its *Reasons for Decision, Proposed Amendment to Export Impact Assessment Filing Requirements*, the Board decided it would produce an EIA, and that applicants could rely on the Board's EIA or file their own. The Board's first EIA was included in that Decision. In addition, the Board said that it would:

> "... periodically produce an EIA using several projections of exports. The study, which will be prepared in consultation with the natural gas industry and other interested parties, will cover long-term natural gas supply, demand, prices and export levels and will endeavour to provide an adequate statement of assumptions and explanation of the analytical techniques used."

The Board has decided at this time to undertake its second EIA, to take into account the long-term gas market outlook in the Board's 1991 report entitled *Canadian Energy Supply and Demand 1990-2010* and to take into account the submissions and comments we received on the first EIA. A draft is contained in the Attachment.

The Board invites comments by interested parties on the attached draft. After reviewing the submissions, the Board will arrange a workshop to promote discussion and exchange of information among participants on the approach taken, the main assumptions and on the issues which arise in the EIA analysis. The Board will then issue its EIA.

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List of Questions

Included in Chapter 4 of the draft is a list of questions to assist interested parties in the preparation of their comments and to provide some common ground among submissions. The list of questions, however, is not exhaustive, nor is it intended to limit the scope of comment.

Timing and Format

1. Letter to interested parties, 3 September 1992.

2. Parties intending to make written submissions are requested to inform the Board by 8 October 1992. Shortly after that date, the Board will prepare and distribute a list of interested parties.

3. Interested parties are required to file 30 copies of their written submissions with the Secretary by 21 November 1992. In addition, interested parties are required to serve a copy of their submissions on each of the other parties indicating an interest in this proceeding.

4. Shortly after 21 November 1992, the Board will release a list of issues for discussion at the technical workshop.

5. The workshop will be held in Calgary on 21 January, 1993.

6. The specific location and format of the workshop will be announced by the Board at a later date.

7. The Board will take account of the information acquired from the submissions and the workshop in preparing the EIA report, for release in the second quarter of 1993.

Viewing of Documents

The following documents will be available for public viewing during normal business hours at the Board's Library, First Floor, 311 6th Avenue S.W., Calgary, Alberta and at the Main Library, Energy, Mines and Resources Canada, 580 Booth Street, Ottawa, Ontario.

1. The Board's EIA Draft, dated August 1992.

2. Copies of the material referenced.

3. Copies of written submissions.

The Board requests that correspondence pertinent to this proceeding, following the above guidelines under Timing and Format (items 2 and 3), be filed with the Board at the following address:

Office of the Secretary
National Energy Board
311 6th Ave. S.W.
Calgary, Alberta
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All parties are requested to quote Board File No. 7500-A000-2.

J.S. Richardson
Secretary

Attachment
to the Board's
letter dated
3 September 1992

Export Impact Assessment

DRAFT

National Energy Board
August 1992

Export Impact Assessment

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Chapter 1 Introduction

1.0 Background: Market-Based Procedure

The Export Impact Assessment (EIA) is one component of the Market-Based Procedure (MBP) used by the Board to make decisions on the licensing of natural gas exports. The MBP was established following a review in 1987 (GHR-1-87) of the Board's surplus determination procedures which derive from Section 118 of the NEB Act:

> "... the Board shall have regard to all considerations that appear to it to be relevant and shall... satisfy itself that the quantity ... of gas to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada having regard to the trends in the discovery of... gas in Canada..."

Implementation of the MBP effectively ended a series of formulistic approaches which had been utilized since 1960 to determine the exportable surplus of natural gas.

The MBP is founded on the premise that the marketplace will generally operate in such a way that Canadian requirements for natural gas will be met at fair market prices. The Board has said it will act in two ways to ensure that natural gas to be licensed for export is surplus to reasonably foreseeable requirements: one way is in the context of public hearings to consider gas export applications; the other is to monitor Canadian energy markets on an ongoing basis[1].

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1. As gas markets have evolved, and as part of the Board's ongoing effort to maintain and improve the clarity and effectiveness of the regulatory process, the MBP has been the subject of ongoing review. In November, 1989, the EIA filing requirements were changed and in March, 1990, the requirement for a benefit-cost analysis (one aspect of Other Public Interest Considerations) was eliminated. Most recently, in GHW-1-91 the Board reviewed the application of some aspects of the MBP. In its Decision, the Board provided a clarification of the operation of the Complaints Procedure, made some small changes with respect to Other Public Interest Considerations, and implemented changes to the pre-hearing process which were designed to streamline the entire hearing process.

A. Public Hearings

During public hearings to consider applications for licences to export natural gas, the Board's assessment as to whether the market is functioning in a satisfactory way consists of three main components: (1) the Complaints Procedure; (2) the Export Impact Assessment; and (3) Other Public Interest Considerations.

B. Ongoing Monitoring

Ongoing monitoring consists of two main components, these being the assessment of Canadian energy supply and demand and the Natural Gas Market Assessment.

1.1 Purpose of the EIA

The purpose of the EIA is:

> "to determine whether a proposed export is likely to cause Canadians difficulty in meeting their energy requirements at fair market prices".

Originally, all applicants for export licences were required to file an EIA. While definitive instructions were not provided, the extent of the analysis, whether quantitative or qualitative, was to be commensurate with the size of the proposed export. Matters to be addressed were initially outlined in the GHR-1-87 Decision, including:

> "the ability of the gas producing sector to satisfy Canadian needs, given the proposed export...";
>
> "any need for Canadian gas users to adjust their energy consumption patterns by means of conservation or switching to alternative fuels..."; and
>
> "the impact of their exports on future natural gas prices... "

The Board also stated that:

> "The burden of proof will rest with the Applicant to satisfy the Board that the proposed export is surplus."

In a letter to interested parties inviting their comments, dated 7 September 1989, the Board stated that two implementation issues had arisen with respect to the EIA during the previous two years of natural gas export proceedings:

> "(1) it is difficult to detect or measure substantial impacts of small proposed export volumes; and

(2) there appears to be uncertainty on the part of applicants about how to best satisfy the EIA requirement. "

To address these issues the Board proposed in the letter some changes to the EIA filing requirements and included an illustrative EIA analysis. Having reviewed the responses from interested parties, the Board released its Decision in November, 1989. It decided to retain the EIA; however, export applicants would no longer be required to file project-specific analyses. The Board stated that it would:

> "...periodically produce an EIA using several projections of exports. The study, which will be prepared in consultation with the natural gas industry and other interested parties will cover long-term natural gas supply, demand, prices and export levels and will endeavour to provide an adequate statement of assumptions and explanation of the analytical technique used."

The Board also stated that applicants and intervenors in a particular export proceeding would have the option of adopting the Board's EIA or of preparing and submitting their own as a basis for arguing whether the proposed export would result in adjustment difficulties in Canadian energy markets.

Subsequent to the release of its EIA Decision, the Board and the Canadian Energy Research Institute sponsored a one-day workshop on the issues surrounding the methodology employed by the Board in its EIA and in its benefit-cost analysis. This provided a forum for further discussion with interested parties.

1.2 Report Outline

In Chapter 2, Approach to the Analysis:

- the approach taken in the first EIA and the results of that analysis are summarized;
- the main issues associated with this type of analysis are addressed, including feedback from interested parties with respect to the first EIA; and
- the approach to this, the second, EIA is outlined.

In Chapter 3, Results:

- the assumptions and results of the Control Case are described; and
- the results of three impact cases are assessed:
  Case 1 - Higher U.S. Demand;
  Case 2 - Higher U.S. Gas Supply Costs; and

Case 3 - Combined Case, i.e., the combined impact of the first two cases.

In Chapter 4, preliminary conclusions are presented and the issues arising from the analysis are discussed. These form the basis for a series of questions to interested parties on the approach and assumptions.

The Appendix contains supporting material.

Chapter 2 Approach to the Analysis

2.0 Introduction

As stated in Chapter 1, the purpose of the EIA is to assess whether additional exports are likely to cause Canadians difficulty in satisfying their energy requirements at fair market prices. The potential impact the EIA is intended to assess has several key components:

(1) incremental exports call forth increasingly costly gas supply over time relative to supply costs without the increment;

(2) the delivered prices of gas to Canadian consumers increase because of the increased supply costs;

(3) consumers either conserve on the use of gas or they switch to other fuels as they become more economic for some users;

(4) this conservation and switching entails an adjustment process which may or may not be easy to achieve; and

(5) development rates of resources are accelerated.

The complexity of the North American natural gas market implies that, for the most part, a quantitative methodology should be employed to assess these impacts. However, there does not appear to be a quantitative approach which can completely assess the dynamics of the adjustment process, thus necessitating a more qualitative assessment of these issues.

2.1 The Board's First EIA (1989)

In the Board's first EIA, the approach taken was to assess the effect of a large increase in natural gas exports on domestic gas prices, demand and production over a 15-year period. The increment was specified to occur against a base case. A large increment was chosen because the impact of small increments would be negligible. This approach could then be used to assess the cumulative impact of several smaller applications.

The base case was taken from the Low Oil Price gas market projections in the Board's 1988 report entitled *Canadian Energy Supply and Demand 1987-2005*. The impact case assumed an increase in annual exports, during the 1990-2005 time frame, of .5 EJ, from

about 1.5 EJ in the base to 2.0 EJ. The impacts were assessed using the Board's Canadian energy models. Hence, the analysis did not consider other adjustments in the U.S., nor the feedback to Canada that would occur as the result of the integration of the two markets. In other words, it was a partial equilibrium approach in that the impact on the Canadian market of changes in the U.S. market was not incorporated in the model.

The base case and impact case assumed the ultimate potential for gas reserves in the Western Canadian Sedimentary Basin to be 225 EJ. This was based on the Geological Survey of Canada's average resource expectation (50% probability estimate). Hence, this part of the analysis was referred to as the "Average Resource Scenario". Oil prices were assumed not to change as a result of changes in the level of gas exports. Recognizing that gas and HFO (heavy fuel oil) are substitutable in industrial use, industrial sector gas prices were assumed to track HFO prices so that the price increase induced by higher gas exports was absorbed entirely by residential and commercial customers.

The analysis indicated that, during the period 1995-2005, the effect of the additional exports would be to raise prices to Ontario and Quebec residential consumers by 9-14%. It was anticipated that Canadian consumers would not experience significant difficulty in reducing their gas consumption by about 4% and increasing their consumption of oil products also by about 4%. However, there would be a need for increased reliance on frontier reserves to provide deliverability in the post-2000 period.

The high degree of uncertainty associated with frontier development, including the distribution of reserves, development costs and environmental issues, caused some doubt as to whether the required gas supplies would be forthcoming. This implied that there was a possibility that the necessary adjustments on the demand side could be larger than estimated. This caused the Board to "eschew firm conclusions...about the adequacies of the adjustment processes".

To reflect the uncertainty associated with the size of the natural gas resource base, the analysis was also undertaken for a "Low Resource Scenario". This assumed an ultimate potential in both the base and impact cases of 190 EJ, based on GSC's low resource expectation (95% probability estimate).

The effect of the Low Resource Scenario was to raise price levels in both the base and impact cases; however, the percentage impacts on prices and demand volumes were similar to the Average Resource Scenario. The requirement for frontier gas supply was accelerated by about 3 years, to 1999 in the base case and 1997 in the impact case.

2.2 EIA Issues

The Board has received substantial comment on matters relating to the EIA analysis in general, and to the first EIA in particular, from three sources:

- from a 1-day workshop sponsored by the Canadian Energy Research Institute (CERI) and NEB on issues surrounding the methodology employed by the Board in its EIA analysis and benefit-cost analysis. The conference was held in November 1989, just after the release of the Board's Decision on changes to the EIA filing requirements, and included participants from the producing and consuming sectors, governments and academia. The proceedings were published as a set of papers, entitled *Workshop on Benefit-Cost Analysis and Export Impact Assessment*, and included the presentations on Export Impact Assessment by Dr. D.E. Armstrong of McGill University, Dr. J.C. Evans of York University, and Mr. D. Taylor of the Ontario Ministry of Energy;

- from interested parties responding to the Board's September 1989 letter inviting comment on suggested changes to the EIA filing requirements. An "illustrative analysis" was appended, which eventually was adopted as the EIA; and

- from an EIA submitted by DataMetrics Limited (DML) entitled *Export Impact Assessment of Mackenzie Delta Gas*, August, 1988.

Overall, these comments pertained to process and technical matters. Process matters included whether the Board's MBP to license natural gas exports required an EIA and, if so, what the filing requirements should be. Technical matters included the measurement of the impact of additional exports, the assumptions to be used and the uncertainty associated with these assumptions and results.

This section focuses on the technical aspects. It begins with comments received on issues which are central to the EIA and related to the concepts of surplus, adjustment difficulties and fair market prices. Next, comments made on the approach to measuring or quantifying the impact are addressed. The section concludes with a discussion on assumptions.

2.2.1 Surplus

At the CERI/NEB workshop, Armstrong stated that the terms "surplus" and "shortage" are well understood in a regulated price environment. However, they have questionable meaning in a market-based system, where prices balance the forces of supply and demand to avert surpluses and shortages. Hence, it is not logical to ask an exporter to relate a future export to a future surplus.

This view was also expressed in the responses of some members in the group opposing the requirement to file an EIA, including the

Alberta Petroleum Marketing Commission, Amoco Canada Petroleum Company Limited, the Canadian Petroleum Association, C.G. Edge & Associates Inc., the Independent Petroleum Association of Canada, Pan-Alberta Gas Ltd., ProGas Ltd., JMC Selkirk Inc., Westcoast Energy Inc. and Western Gas Marketing Limited. Competition in the marketplace would balance supply and demand and, as a result, adjustments would occur through the operation of the market mechanism.

Comment

With the implementation of the MBP, the Board effectively abandoned formulistic approaches to assessing whether additional exports are surplus to foreseeable domestic requirements. In the EIA, the approach has evolved to assessing potential domestic price impacts and difficulty associated with demand and supply adjustments. If these are gauged to be not extreme or manageable, then the supposition is that the applied-for export volume is not "needed" in Canada and hence, is surplus to Canadian requirements.

2.2.2 Adjustment Difficulties

Identifying adjustment difficulties that could result from additional exports is central to the EIA's expressed purpose.

Armstrong stated that there were a number of problems associated with measuring the fuel-switching capabilities of Canadians, including differences in personal preferences and the relative prices of competing energy sources. If gas were only slightly more expensive than oil, most householders would not switch. On the other hand, multi-fuel steam generating utilities would switch for very small price differences. In both cases, transaction costs and switching costs would have to be taken into account. In a longer term analysis, time lags, changes in technology and environmental requirements would also have to be considered. Consequently, Armstrong doubted that an accurate assessment of fuel switching over a 20-year period could be made.

Evans stated that the conclusions of the Board's first EIA may be too indeterminate to provide a quantitative basis for saying whether additional exports would cause the market to have difficulty meeting foreseeable Canadian requirements. One reason why economic models have problems answering this type of question is that, by their nature, they have few discontinuities or adjustment lags, except where they are explicitly introduced. Unless adjustment lags are built in, it is unlikely that a model will predict future adjustment difficulties.

Taylor pointed out that, in a "shock" situation, such as with sharply higher oil prices, consumers would not have time to adjust by way of conservation and fuel switching. As well, in this shortened time frame, producers would not be able to bring forward

the required supplies. The situation would be exacerbated by a commitment to higher exports.

DML addressed adjustment capabilities in the EIA submitted for Mackenzie Delta gas. The analysis was couched in terms of demand and supply elasticities, i.e., the responsiveness to price changes of quantities demanded and supplied .

Having reviewed the evidence on fuel substitution and the impact of higher gas prices in Canada during the 1970s and 1980s and having assessed forecasts available at that time (August, 1988), DML concluded that, over the long term, Canadian energy consumption patterns could adjust quite well to changes in the price of natural gas. However, because of the many factors influencing natural gas demand, including the price of and preference for other fuels, it is difficult to obtain precise knowledge about the rate of change of the adjustment in gas demand to price.

In the very short term, DML stated that the Canadian gas market has significant flexibility to switch fuels as evidenced by interruptible contracts and dual-fuel capability utilized by industrial consumers. While this did not demonstrate a long-term switching capability, it was at least evidence of the potential ability of markets to adapt.

On the supply side, DML concluded from a review of studies, including those done by NEB, EMR, ECC and others (e.g., Euler, Mansell and Wright), that the supply of gas in Canada is price responsive. This contradicted the view that increased exports would result in shortages later on for Canadian consumers.

Comment

As indicated by some participants and submittors, the measurement of adjustment difficulties presents formidable estimation problems.

The approach taken in the Board's first EIA was to examine the impact on market trends and then assess "what has to happen" in terms of consumer and producer adjustments. In that it was the end result that was assessed, it was not known whether the adjustment process was "difficult". It remains a question for discussion whether adjustment difficulties can be assessed, or whether the EIA should have the more modest goal of assessing the magnitude of the impact of increased exports on Canadian gas users.

It is true that a shock resulting, for example, from a sharp change in oil prices could require a rapid short-run supply and demand response. However, such shocks cannot be foreseen and any necessary regulatory response would have to be considered in light of the particular circumstances.

2.2.3 Fair Market Prices

Armstrong stated that a market price is based on there being choice between buyers and sellers, competition among buyers and sellers and bargaining. Prices established in this manner are most efficient from the standpoint of resource allocation.

Prices set by governments are unlikely to yield better results even when trying to take into account environmental considerations and the value placed on gas by future generations."It is probably safe to assume that market prices are likely to be just as fair to future generations as any other price regime that has any hope of being adopted by the present generation".

Armstrong also considered the difficulty Canadians might have in meeting their consumption requirements because of high demand (and therefore, higher prices) from U.S. sources. His view was that both U.S. and Canadian consumers would behave according to their demand functions; that is, with higher prices resulting from increased demand, both American and Canadian consumers would re-evaluate their options and reduce the demand for gas in less-valued uses. Moreover, higher prices would result in a positive supply response.

Armstrong expressed the concern that if supplies to the U.S. were in some way constrained so as to mitigate or lower the price to Canadians, such "lower" prices would not necessarily be "fair", when considering the viewpoint of producers and resource owners. Further, in a free-trade environment, such efforts at cross-subsidization may provoke retaliation with negative effects on other domestic sectors. It should be presumed, therefore, that Canadians will accept the advantages and disadvantages of world energy prices in gas as they do for other commodities including oil.

Mr. Taylor's view was that "reasonable people can differ on what is fair". It could be argued that, in a properly functioning market, whatever price is arrived at is fair. In this regard, the Complaints Procedure provides an important indication whether the market is functioning properly and thus whether the price will be fair.

DML's view was that a fair market price would be one which would emerge from the operation of competitive markets. However, this criterion would provide little comfort to domestic consumers if price inelastic supplies of gas faced price inelastic demands. Hence, fair pricing would require the pricing mechanism to arbitrate between supply and demand smoothly rather than abruptly. A precondition would be that both supply and demand exhibit a reasonable degree of response to price variations.

Comment

To the extent that the market is allowed to function, the market should be the arbiter of price determination. As suggested by some participants, such prices would be "fair" provided that they are established on the basis of market forces in a competitive market.

2.2.4 Measurement of Impact

There was substantial comment on matters relating to quantification of impacts.

Armstrong stated that the critical variables underpinning long-term forecasts cannot be effectively predicted and that the limitations of econometric models should be recognized. Therefore, forecasts should never be single valued; there should be "literally scores of forecasts to match the scores of assumptions that can be made about the future."

Armstrong's view was that it would be preferable to utilize such models in Part B (Monitoring) rather than to utilize them as a decision tool in Part A (Public Hearings) to accept or reject exports to the U.S. Part of his concern stemmed from the potential for there to be a proliferation of "little black boxes" built to serve vested interests. He concluded that an EIA should not be a requirement for an export license.

Evans made a number of specific comments with respect to the methodology utilized in the Board's first EIA. He noted that the Board had taken a partial equilibrium approach and had made the following observations:

- there was no assurance that the chosen incremental exports of 550 PJ per year would in fact occur; hence, the prospect might be considered hypothetical; and

- the partial equilibrium (PE) approach, which assumes the full extent of the impact of additional exports is borne by the Canadian market, could well show different results than a general equilibrium approach (GE), which recognizes impacts on prices and volumes occurring in the broader context of a North American market.

Evans concluded that the Board should use a GE approach such as that taken in the North American Regional Gas Model (NARG). NARG might require extensions, such as to incorporate the more detailed demand formulation of the Board's model.

Taylor's view was that both the PE and GE approaches were useful. PE would be appropriate to answer the "what-if" question. He stated that the strength of the Board's approach was in the detail on the demand side, which recognized conservation and substitution among

the four major fuels and with detailed sectoral and end-use responses to price.

The GE approach, on the other hand, would be appropriate when there are strong feedbacks between the Canadian and U.S. markets. GE is useful to examine such questions as the conditions that would be required to sustain a higher export level, eg, higher U.S. demand or lower Canadian costs.

With respect to utilizing the NARG model for export impact assessments, Taylor stated that a number of features of NARG should be borne in mind. The assumption of perfect knowledge always causes supplies to be brought on as required, and in order of cost. Hence, the model often indicates "what ought to be as opposed to what might be". On the demand side, core market demand is almost unaffected by price while the non-core market is highly sensitive to relative prices of oil and gas. This would tend to overestimate the industrial sector's capability to switch fuels. Taylor said these caveats were relatively minor if the model results are interpreted with them in mind.

Submissions by APMC and Union tended to support the use of a GE approach, for similar reasons as given by Evans and Taylor. APMC submitted that to not use a general equilibrium approach was inconsistent with the fundamental premise of the Market-Based Procedure.

Comment

To assess the impact of prospective exports on Canadian prices and whether Canadians will experience difficulty in meeting their energy requirements implies some form of quantification, or estimation. The main issue raised on this matter by participants and submittors was the use of an approach which recognizes the integration of the U.S. and Canadian markets (GE) versus the approach of treating the Canadian market in isolation (PE).

As stated in the Board's 1989 EIA, there is merit in both kinds of analyses. GE frameworks are better able to portray aggregate impacts among related markets whereas PE frameworks can provide better sector by sector insight.

The EIA analysis does assume a hypothetical situation and there is no assurance that the chosen increment of exports will in fact occur. However, this is true of all analyses of the prospects for North American gas markets in that they are all conditioned by assumptions about a large number of variables about which there is considerable uncertainty.

2.2.5 Assumptions

A number of specific comments and suggestions were made on the assumptions in the 1989 EIA.

Taylor suggested that the increased requirements for Canadian production would require a sustained increase in drilling levels which would be high by historical standards. This could create inflationary pressures on supply costs, and he questioned whether it was reasonable to assume that exploration and development would respond as predicted.

Taylor also questioned the assumptions about the timing and price impact of frontier resources, e.g., what the consequences would be for Canadian consumers and pricing if this development were delayed. The assumption of continuously rising supply costs for frontier gas could also result in an overstatement of these costs, after the hurdle of the first pipeline is overcome.

Taylor noted the uncertainty surrounding estimates of the ultimate potential of gas reserves and accordingly, the EIA had been conducted on the basis of two resource scenarios ("Average" and "Low"). In view of the impact of differing assumptions on gas supply costs, he suggested that ways be investigated to narrow this uncertainty.

On the demand side, Taylor stated that Ontario's gas requirements for electricity generation could be considerably higher than the Board estimate. As well, given the investments made in the 1970s and 1980s to go "off oil", consumers might be reluctant to switch back if gas prices rise. This would increase adjustment difficulties and the impact of rising prices on consumers.

Armstrong emphasized the need to vary assumptions to recognize the uncertainties of the future. Gaz Métropolitain inc., ICG Utilities (Ontario) Ltd. and Union Gas Limited indicated that interested parties should have the opportunity to comment on, and provide input to, the assumptions to be used in a Board-prepared EIA.

Comment

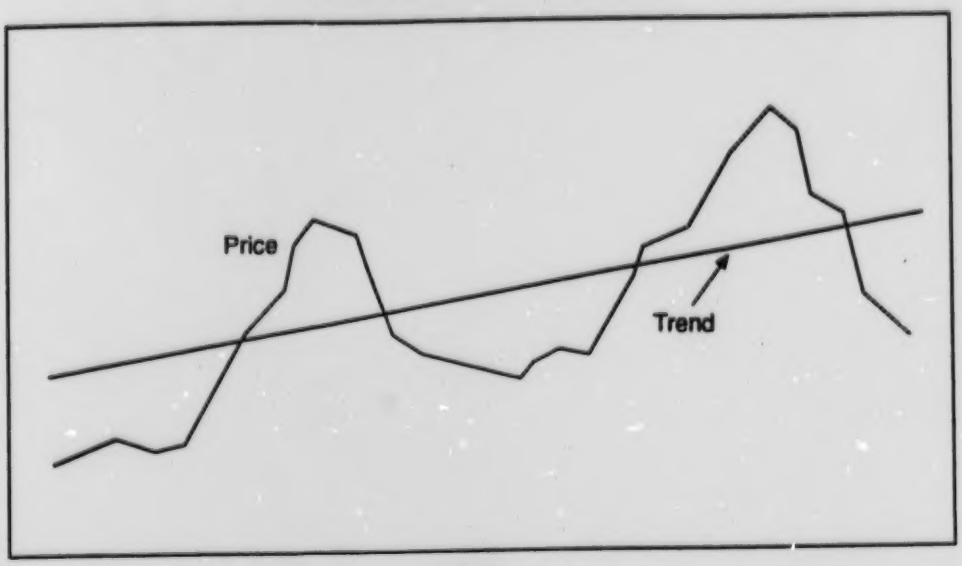
As noted above, all analyses of the genre utilized in the EIA are subject to a large degree of uncertainty. This uncertainty stems from the range of values that may be associated with the so-called "independent" (input) variables and from the nature of the causal relationship that exists between the independent and so-called "dependent" (output) variables.

The first type of uncertainty can be dealt with by assessing the implications of a range of values for key inputs to the analysis. The second type of uncertainty is particularly daunting in the case

of commodities such as natural gas. While the causal relationship between price and the quantity demanded, and between price and the quantity supplied may be reasonably well understood, the inherent lags to changing supply and demand levels cause prices to be volatile.

A stylized representation of commodity price behaviour is illustrated in Figure 2-1. Main features include potentially large price changes over a relatively short period - or volatility, a discernible trend and prolonged periods when prices may be above or below trend[1].

Figure 2-1
Commodity Price Behaviour



In the Board's analysis, an attempt is made to derive the underlying price and volume tracks based on average relationships describing the responses by consumers and producers to price expectations. Hence, there is no specific attempt to capture the inevitable volatility, recognizing that, over certain periods, there could be substantial variation from underlying trends. For example, natural gas prices are currently very low. Over time, they may well rise above the long-run trends analyzed in this report.

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1. A review of commodity price trends during 1985-1991 is contained in a recent paper by A. Plourde and G.C. Watkins, *Crude Oil Prices: How Volatile ?*, preliminary draft, May, 1992 (presented at a conference sponsored by the International Association for Energy Economics).

2.3 The Board's Second EIA (1992)

This section provides a brief description of the approach taken in this EIA and a discussion of the rationale behind the Control and impact cases. Results are presented in the next chapter.

2.3.1 General Equilibrium Approach

To quantify the impact of additional exports on Canadian gas prices, demand and production, a general equilibrium (GE) approach has been utilized. This takes account of the integrated nature of U.S. and Canadian gas flows and price determination. This approach fundamentally differs from the partial equilibrium (PE) approach of the first EIA which tended to reflect the entire impact on the Canadian gas market. Additionally, the first EIA assumed additional exports to be "given", without regard to specific underlying conditions in the gas market which might cause them to occur.

The GE framework which has been used is embodied in the North American Regional Gas (NARG) Model. A brief overview is provided below, followed by some expansion on the supply-side and demand-side aspects of the model. Additional explanation is given in the Appendix and in 1991 SD, Chapter 6.

NARG is a generalized equilibrium model of the North American gas market. The model takes an exogenous demand projection as a starting point and then iterates between supply and demand to produce a price projection over the study period which is consistent with a matching of supply and demand.

Supply cost curves describe the quantity of gas available at a given price. This gas volume is then passed to end users through a representation of the North American pipeline and distribution network. Pipeline tolls, distribution margins, fuel use and losses are added to supply costs to determine delivered prices to end users. Prices and quantities are then determined by iteration to simultaneously satisfy all relationships in the network at each point in time. In other words, the market clears in each time period.

In this North American framework, Canadian gas competes with U.S. gas. Hence, Canadian prices can be expected to follow prices in the U.S., with differences between Canadian and U.S. wellhead prices reflecting transportation differentials.

2.3.1.1 Gas Supply

Gas is obtained from 17 producing regions in North America[1] and from imported LNG. The six Canadian supply regions are B.C., Alberta, Saskatchewan, Northern Canada (Mackenzie Delta), Arctic

Islands (no projects in the Board's scenarios) and Eastern Canada (Venture project).

Natural gas is modelled as a depletable resource with a fixed level of ultimate resource potential and ever-increasing marginal costs. Though many, if not most, gas market analysts are willing to grant the plausibility of this assumption in a very long-run context, an increasing number are questioning whether it provides a suitable focus for analysis over shorter study periods, such as 10-15 years.

The process of price formation recognizes -- in addition to the direct costs of exploration, development and production -- the choice facing a producer of producing gas now or at some point in the future. This choice will be dependent on the producer's and resource owner's discount rates and their perception of future prices, including the "backstop price"[2]. The production profile is configured so as to maximize the present value of the difference between the revenue and cost streams. This difference is referred to as "user cost". An ideal royalty and lease bid system is assumed in which the resource owner receives the entire user cost and the producer recovers his costs and earns a normal rate of return on invested capital.

This process of price formation has its foundations in a seminal article by Hotelling, and has evolved over time as a fundamental concept in the analysis of "exhaustible resources". The history of natural gas prices suggests that the market may not behave in accordance with this model of price formation. Whether the traditional view of natural gas as a depletable resource subject to increasing supply costs over time or the currently popular view of natural gas as an abundant commodity will prevail is uncertain at this time. This analysis is based on the traditional view.

2.3.1.2 Gas Transmission and Distribution

Within NARG, gas transmission between regions is accounted for by 123 pipeline corridors, representing either individual pipelines or a collection of pipelines with similar characteristics. Tolls are determined on a "levelized" basis, including demand and variable charges. For the most part, tolls are assumed to remain constant in real terms, the assumption being that pipeline expansions are offset by depreciation of the existing rate base.

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1. Within a region, gas supplies are classified into as many as five categories: onshore - conventional and deep, offshore - conventional and deep and coal bed methane.
2. The backstop price of $7 US/Mcf (1991$), assumes a combination of coal-bed methane, frontier resources, coal gasificaton and LNG.

The city-gate gas price (before addition of distribution charges) within a market area is the same to all end-use sectors; there is no price "streaming".

Distribution margins are lowest in the industrial and electricity generation sectors and highest in the core sector to reflect the relative costs of providing service. Hence, gas price changes will have the largest impact, in percentage terms, in switchable markets. Margins are assumed to remain constant in real terms over the study period.

2.3.1.3 Gas Demand

North American demand is disaggregated into 17 consuming regions, and into core, industrial and electricity generation sectors within each region. The four Canadian regions are Quebec, Ontario, Western Canada and British Columbia.

The core market includes residential and non-cogeneration commercial gas users. The industrial market includes all non-cogeneration industrial gas and HFO (heavy fuel oil) users[1]. Electricity generation includes all utilities using gas, HFO or LFO (light fuel oil), as well as commercial and industrial gas-fired or oil-fired cogenerators.

It is assumed that core market gas users are unable to switch to alternate fuels. In the Canadian industrial market, it is assumed that 25% of gas users will be unable to switch to alternate fuels. However, the remaining 75% of gas users and 100% of HFO users can develop, over a period of years, the ability to switch between gas and HFO. In the electricity generation market, consumers can switch between gas and HFO or between gas and LFO according to generating technology. These assumptions about the ability of industrial and electricity generation users to switch between gas and HFO have important implications for the results of the analysis, as outlined in Chapter 3.

Demand is determined by a reference price-quantity relationship and a short and long-run price elasticity. Responses to changes in gas prices are stronger in switchable markets (compared to core markets) where the conservation effect is supplemented by the substitution effect. A rise in gas prices relative to oil prices causes gas demand in switchable markets to decline and oil demand to increase.

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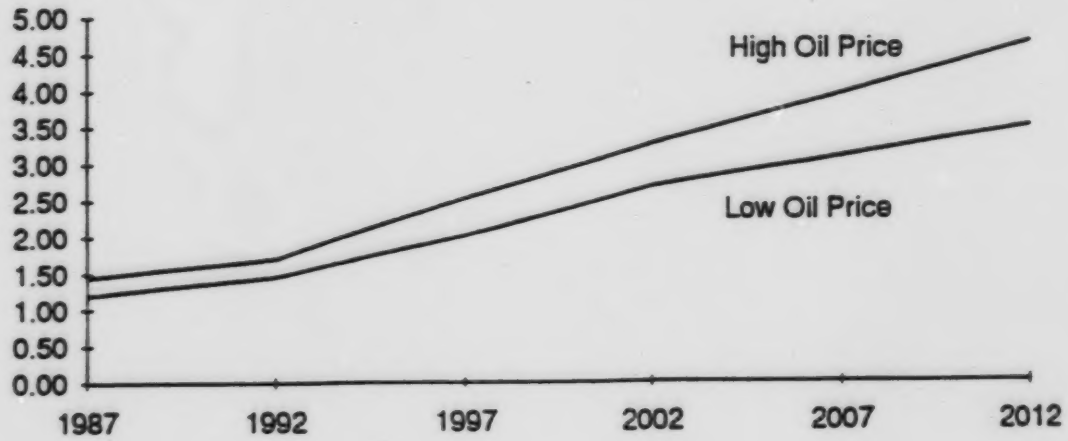
1. This definition of the industrial market, i.e, excluding industrial oil-fired and gas-fired cogeneration, corresponds to the "non-core" market.

Table 2-1
Description of Natural Gas Cases[a]

Case	Canadian Resource[b] (EJ)	U.S. Resource[c] (Tcf)	Oil Price ($1990 U.S./bbl)	Description
1	250	1415	20 - 27	Control
2	250	1415	22 - 35	High Oil Price
3	250	1415	18 - 20	Low Oil Price
4	200	1415	20 - 27	Low Canadian Resource
5	300	1415	20 - 27	High Canadian Resource
6	300	1701	20 - 27	High North American Resource
7	250	1415	20 - 27	Low Backstop ($5.00 C 1990/GJ)

[a] The purpose of this table is to show the key parameters changed in the sensitivity cases relative to the Control Case.
[b] Canadian resource estimates included in this table are for the WCSB only.
[c] U.S. resource estimates included in this table are for the Lower-48 states only.

Figure 2-2
Alberta Fieldgate Gas Price
Range of Results – $C 1990/GJ



Source: *Canadian Energy Supply and Demand 1990-2010*, NEB, 1991: Table 6-11 and Figure 6-37.

In the basic configuration of NARG, it is assumed that each fuel will command an equal share of the switchable market when the prices of competing fuels are equal. In this analysis, it is assumed that end-users will be willing to pay a premium for the use of gas over the use of HFO due to the relative ease of obtaining, distributing and burning gas (HFO requires on-site storage, cleaning of burners, etc.). To reflect this premium, it is assumed that gas prices will exceed HFO prices by 5 % in Quebec and by 7 % in Ontario and the rest of Canada before HFO commands an equal share of the market with gas. The assumed premium is lower in Quebec to account for easier access to imported HFO supply.

The directional impacts of price effects and the relative ease of fuel substitution would appear to be properly represented. That is, if gas prices rise to and above the level of oil prices, the effect on core gas demand would be a relatively small demand reduction and very minor levels of fuel switching. The effect on industrial gas markets would be relatively large, with significant switching to HFO. However, the extent and timing of these demand adjustments, especially in the industrial sector are quite uncertain.

2.3.2 Control and Impact Cases

The Control Case is based on the Control Case from the Board's 1991 report entitled *Canadian Energy Supply and Demand 1990-2010* (1991 SD). In that report a number of alternative cases were analyzed, to recognize the uncertainty associated with a number of key variables, including:

- Oil prices - High and Low
- Canadian natural gas resources - High and Low
- North American natural gas resources - High
- Backstop Price - Low

The case assumptions are summarized in Table 2-1 and the range of results for prices and volumes are indicated in Figures 2-2 through 2-5. It is evident that there are substantial variations depending on the combination of market conditions assumed.

In this analysis, the alternatives examined in 1991 SD are supplemented with three cases which could lead to a higher demand for Canadian gas. These are based on alternative assumptions about conditions in the U.S. market which could lead to higher Canadian exports.

Figure 2-3
North American End Use Demand
Range of Results – Exajoules/Year

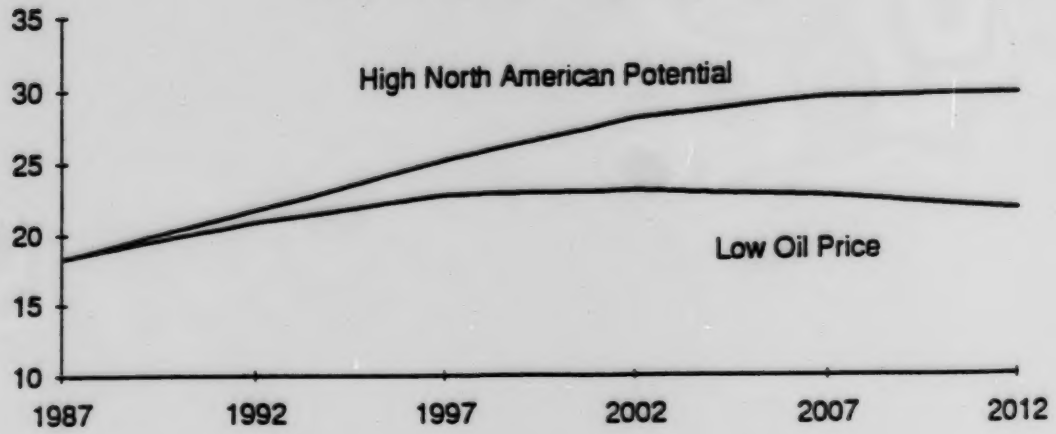


Figure 2-4
Net Canadian Exports
Range of Results – Exajoules/Year

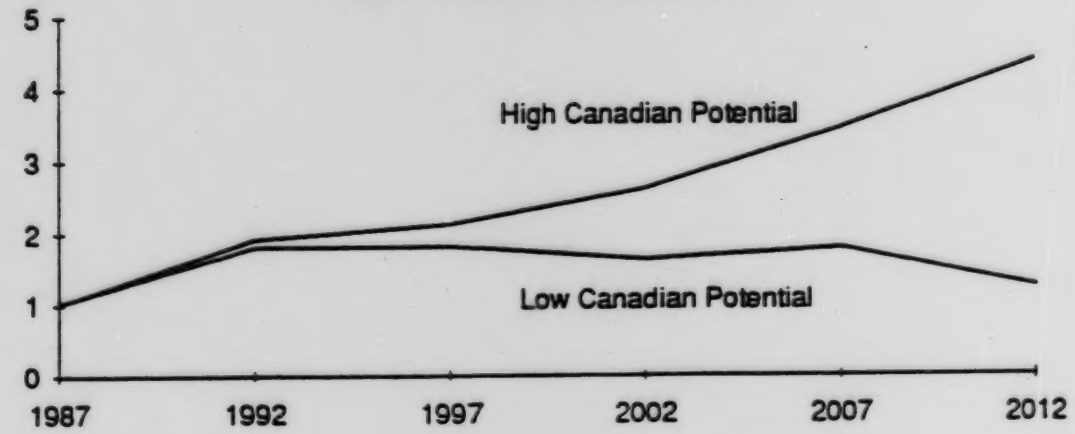
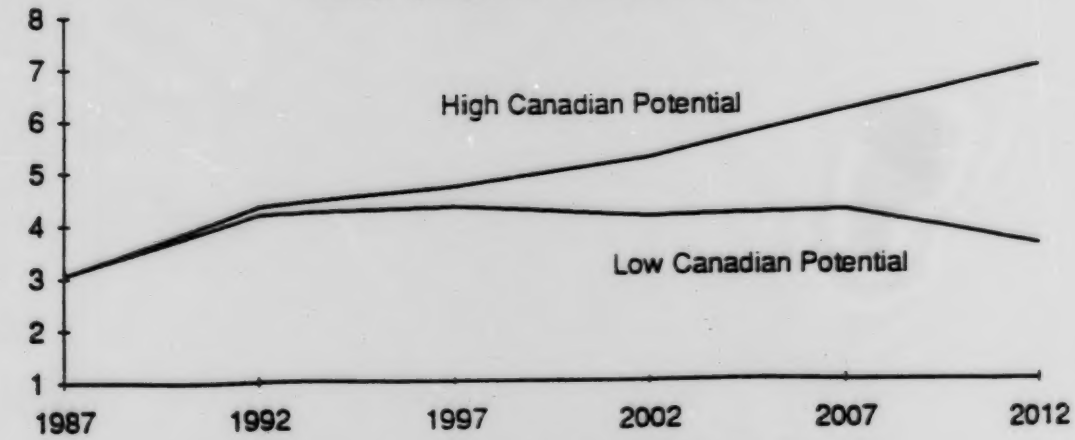


Figure 2-5
Canadian Natural Gas Production
Range of Results – Exajoules/Year



Source: *Canadian Energy Supply and Demand 1990-2010*, NEB, 1991: Figures 6-38, 6-39 and 6-40.

Case 1 - Higher U.S. Demand

U.S. demand is gradually increased after 1992 to reach 10 % above the Control case levels by 1997 and for the remainder of the study period. This triggers a series of price and volume responses in both the U.S. and Canadian markets. Generally, higher U.S. demand causes higher cost sources of gas to be accessed sooner resulting in higher prices. Higher prices feed back to U.S. demand partially offsetting the initial demand increase. Higher prices stimulate both U.S. and Canadian production so that the demand increase is shared between these two sources and increased LNG imports. Canadian production does not increase as much as exports because higher prices, caused by the earlier reliance on higher cost gas supplies, reduce Canadian domestic demand.

Case 2 - Higher U.S. Costs

U.S. costs of exploration, development and production are gradually increased after 1992 to reach 25 % above Control case levels by 1997 and for the remainder of the study period. Higher costs make U.S. gas production less competitive relative to Canadian gas, thereby encouraging more Canadian imports. However, even with increased Canadian imports, U.S. consumers face higher average gas prices, causing them to reduce gas demand by conservation and fuel switching. In Canada, higher exports cause earlier reliance on higher cost gas supplies resulting in higher gas prices. The reduction in Canadian domestic demand caused by higher gas prices partially offsets the increase in production due to higher exports.

Case 3 - Combined Case

The assumptions of Case 1 and Case 2 are run simultaneously. This case produces the largest effects on Canadian exports, production and prices because the assumptions of higher U.S. demand and costs tend to be reinforcing.

Chapter 3 Results

3.0 Introduction

This chapter addresses the results of the Control and impact cases. Firstly, overall trends for the main indicators of gas market activity are examined, including:

- U.S. demand
- U.S. supply (production and imports)
- Canadian exports
- Gas prices
- Canadian demand
- Canadian production.

Secondly, regional impacts are addressed with regard to specific trends in sectoral pricing, consumption and fuel substitution. Thirdly, the implied demand-side and supply-side adjustments are addressed. The chapter concludes with a comparison of this EIA with the 1989 EIA.

3.1 Control Case

3.1.1 Economic Assumptions

The economic assumptions underlying the analysis are the same as contained in the Board's 1991 report entitled *Canadian Energy Supply and Demand 1990-2010* (1991 SD):

- World oil prices are assumed to exhibit little real growth over the 1990s, attaining $23 U.S./bbl (WTI basis, 1990 dollars) by 2000, then increasing to $25 by 2005 and $27 by 2010. This is the mid-point of a range of sustainable oil prices.

- U.S. economic growth averages 2.3% per year during 1990-2010 and Canadian growth averages 2.2%.

- U.S. inflation, as measured by the GDP implicit price index, averages 4 % per year while Canadian inflation averages 4.5%.

- The Canadian dollar in U.S. funds is assumed to decline to $.80 U.S. by 1993, then remain at that level for the remainder of the study period.

Figure 3-1
U.S. Gas Demand by Sector
Control Case

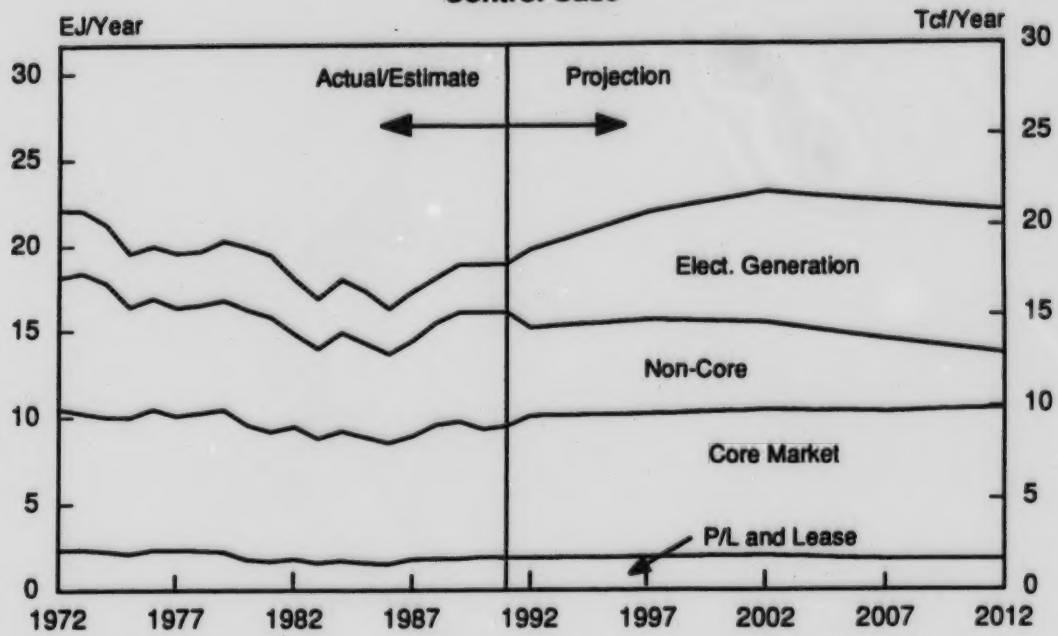
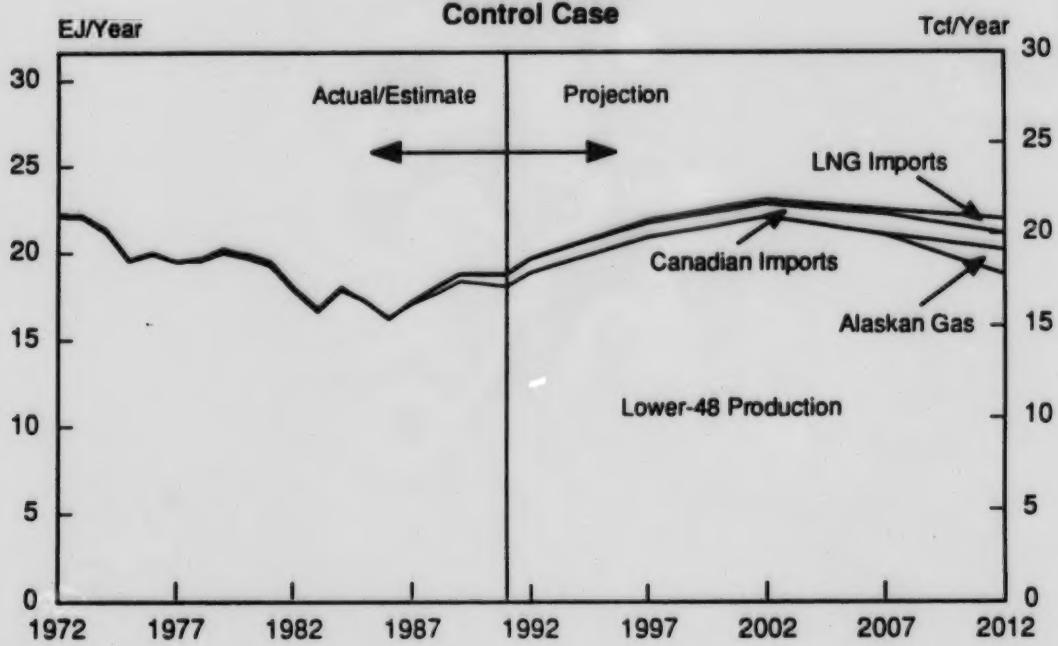


Figure 3-2
U.S. Gas Supply
Control Case



As discussed in Chapter 2, the NARG model requires an exogenous natural gas demand projection to initiate the solution of a specific case. In this analysis, U.S. demand is based on the U.S. Gas Research Institute's 1990 Baseline projection, with some modifications by Board staff, such as inclusion of the Iroquois project in the U.S. Northeast. Canadian demand is based on 1991 SD. On the supply side, the analysis adopts the cost curves utilized in 1991 SD.[1]

3.1.2 U.S. Gas Demand

Gas demand trends by sector are illustrated in Figure 3-1. Total demand is estimated to grow to about 23 Tcf/y by 2002, as compared to 18.8 Tcf/y experienced during 1989-1990. Much of this growth is attributed to environmental considerations, particularly in California and the northeastern states, and to gas-fired electricity generation by both utilities and independent power producers. The so-called "core market" (residential plus commercial sectors, excluding commercial cogeneration) exhibits slight growth while the "non-core" market (industrial, excluding cogeneration) remains flat. During 2002-2012, U.S. gas demand declines to about 22 Tcf/y. This is caused by gas prices rising above HFO prices with resultant loss of market share in the non-core market.

3.1.3 U.S. Gas Supply

U.S. gas supply is composed of Lower-48 production, Canadian imports, LNG imports and N. Alaskan gas later in the projection period (Figure 3-2). Relatively small volumes continue to be produced for local consumption and export from S. Alaska. In this analysis, there are no exports from the U.S. to Mexico and, in a longer term context, Mexican gas is assumed not to be available for export to the U.S.

Over the next decade, demand is primarily accommodated by a combination of increasing Lower-48 production and Canadian imports. In addition, spare capacity in existing facilities is utilized for increasing LNG imports.

After the turn of the century, Lower-48 production declines. Increasing costs limit the amount of gas yielding a competitive return to producers while remaining competitive in the marketplace with HFO. Canadian imports begin to decline after 2007 when N. Alaskan gas commences to flow and LNG imports increase to more significant levels. LNG imports increase to about .8 Tcf/y by 2012 and are assumed to be available at a landed cost of approximately -

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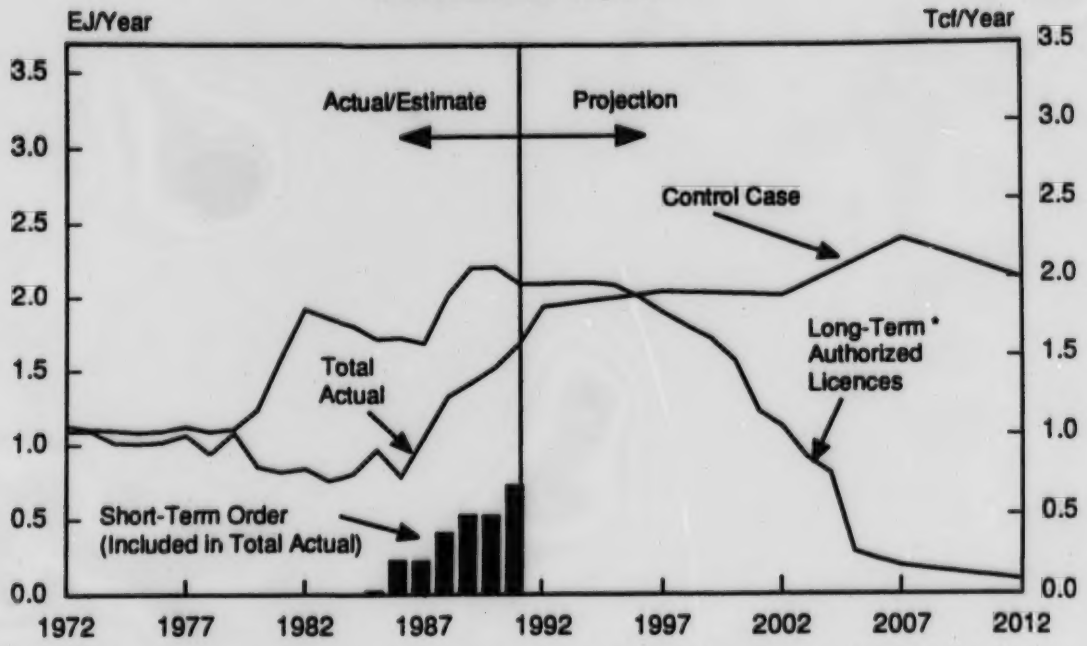
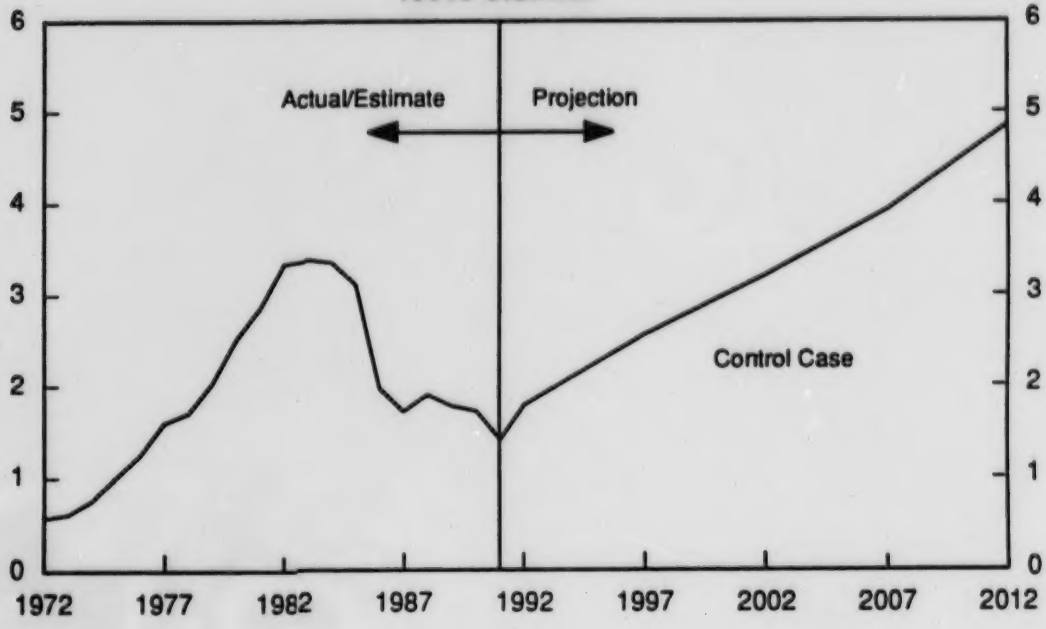
1. NARG is used to approximate the Canadian supply and demand results of 1991 SD. This "Control Case" then becomes the basis upon which to run consistent "impact" cases, without having to use the Board's more detailed supply and demand models.

Figure 3-3
Canadian Gas Exports



* Refers to the total authorized volume under all licences in a given year, including those licences which have not been utilized.

Figure 3-4
Lower-48 Fieldgate Gas Price
1991$ U.S./Mcf



85% of crude oil, thus resulting in gas prices in the range of $4-5 U.S./Mcf (1991 $ U.S.).

3.1.4 Canadian Exports

The results of the analysis suggest that Canadian gas will continue to be competitive in the U.S. market. The Control Case indicates that exports in the range of 2 Tcf/y can be maintained over much of the study period. As Figure 3-3 illustrates, this is clearly above the level of licensed exports currently authorized by the Board. Thus the export projection suggests that Canadian exporters will be able to replace or renew expiring contracts.

Figure 3-3 also illustrates the increasing amount of exports in recent years flowing under NEB short-term orders (approval for a period of less than two years). In that this is a long-term analysis, more focused on the total requirement for Canadian gas in the U.S. market, there has been no attempt to estimate the breakdown of the total export projection between long-term and short-term authorizations.

3.1.5 Natural Gas Prices

Price determination in this long-term analysis reflects "full-cycle" costs of exploration, development and production, and includes a competitive return to producers. The amount of supply forthcoming is constrained by marketplace competition. This places an upper bound on market prices, producer netbacks (market price less transportation and distribution costs) and consequently, the amount of production from a specific source.

The Control Case projection of U.S. prices follows:

Table 3-1
U.S. Fieldgate Prices and LNG Imports
Control Case - 1991$ U.S./Mcf

	1992	1997	2002	2007	2012
Lower-48	1.78	2.55	3.21	3.92	4.85
LNG Imports	3.03	3.39	3.96	4.85	4.77
Alaskan Gas	N/A	N/A	N/A	.89	1.33

The Control Case implies that, based on the assumptions in this analysis, there will be significant upward pressure on natural gas prices over the next decade, in contrast to the soft market conditions that have characterized the gas business over the past several years.

Figure 3-5
Alberta Fieldgate Gas Price
1991$ U.S./Mcf

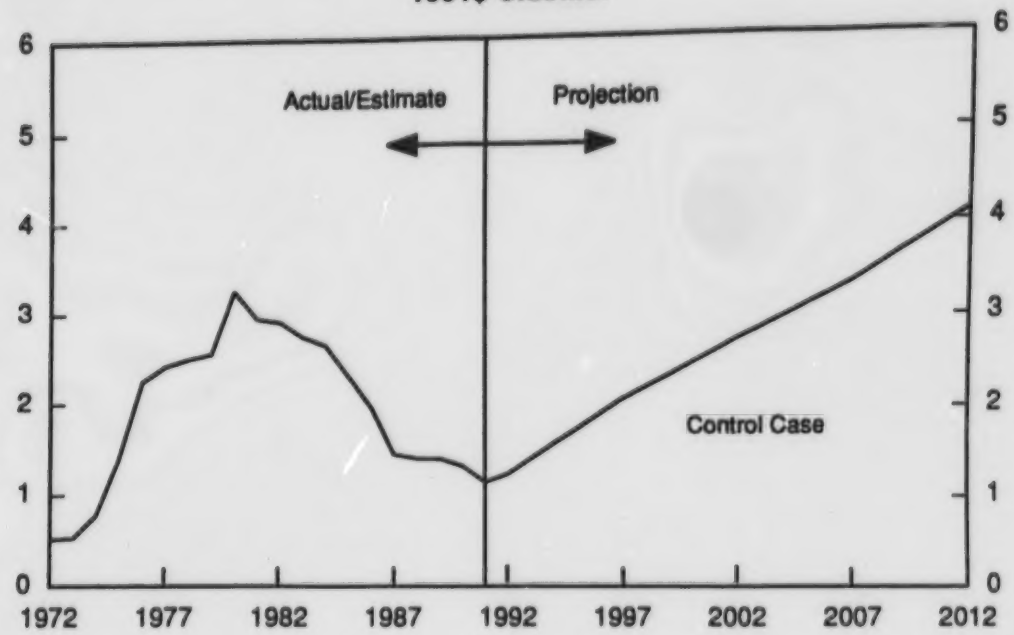
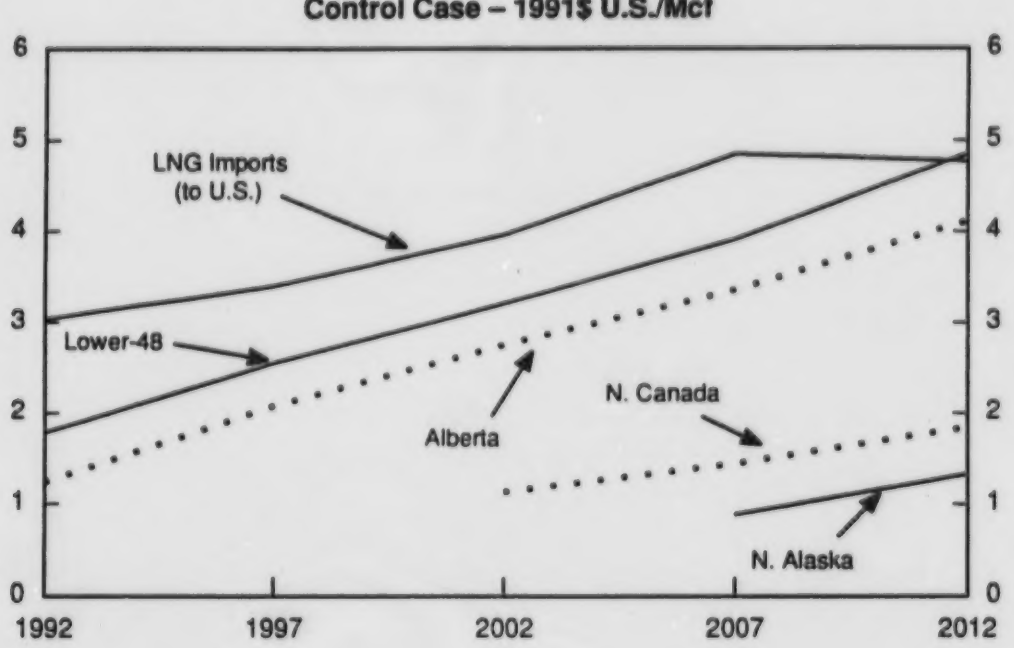


Figure 3-6
Fieldgate Gas Prices
Control Case – 1991$ U.S./Mcf



As noted earlier, the integration of the U.S. and Canadian markets results in Canadian prices closely following U.S. trends. Canadian prices are summarized in Table 3-2.

Table 3-2
Canadian Fieldgate Prices
Control Case - 1991$ U.S./Mcf (1991$ Cdn/GJ)

	1992	1997	2002	2007	2012
Alberta Plant Gate	1.26 (1.47)	2.07 (2.45)	2.75 (3.20)	3.36 (3.80)	4.11 (4.54)
N. Canada	N/A	N/A	1.13 (1.31)	1.45 (1.64)	1.84 (2.03)

Arguably, these gas price projections should be lowered, or price increases deferred, until the "surplus" has eroded. Recent U.S. prices, in the range of $1.40-$1.50 U.S./Mcf[1], and even lower Canadian prices, reflect short-run marginal cost pricing and may well be insufficient to cover full-cycle costs. Over the longer term, the underlying supply and demand conditions will dominate.

The supply side will play a dominant role in determining the eventual path of future gas prices. As noted earlier, there is considerable uncertainty surrounding the magnitude and costs of natural gas resources. This analysis assumes that rising demand will necessitate the exploitation of higher cost reserves. Alternatively, it could be assumed that a set of circumstances such as a larger resource base or technological improvements will result in lower supply costs. This in turn could keep prices at lower levels for an extended period of time. This potential outcome has not been specifically examined.

Canadian consumer prices (Table 3-3) reflect the trends in producer prices, with the addition of transmission and distribution margins. Non-core gas prices in the early years of the projections are below HFO prices and then rise above HFO, thus creating an incentive to substitute HFO for gas.

In the core market, the impact on demand of higher (real) energy prices is limited to the effect brought about by conservation. Over time, substitution can occur as equipment is replaced either through retro-fitting or changes in the housing stock.

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1. U.S. annual average wellhead price in 1990 and 1991 (1991 dollars).

Figure 3-7
Canadian Gas Demand – Control Case

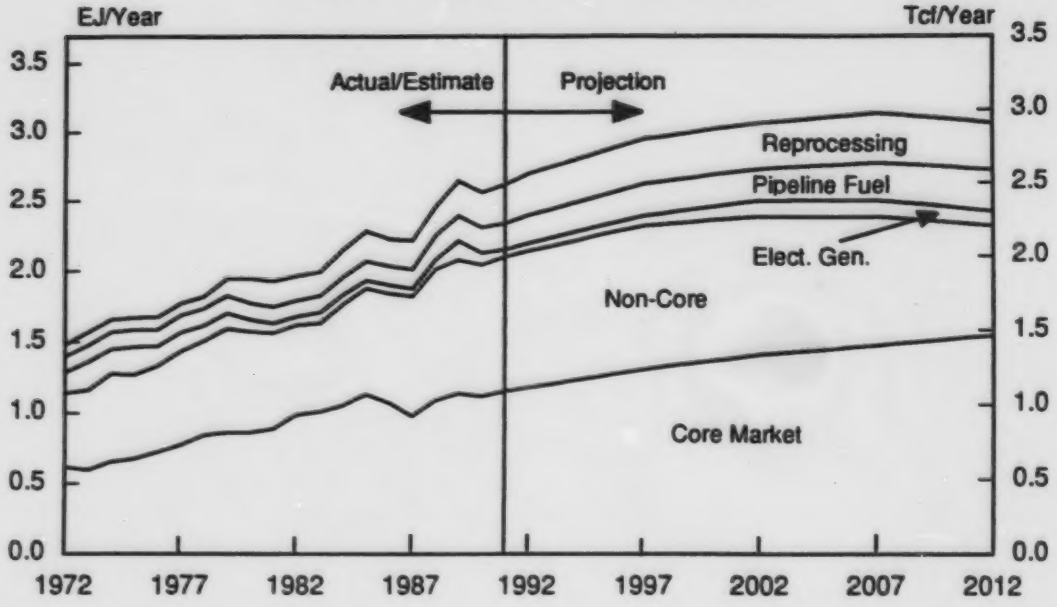


Figure 3-8
Canadian Gas Disposition - Control Case

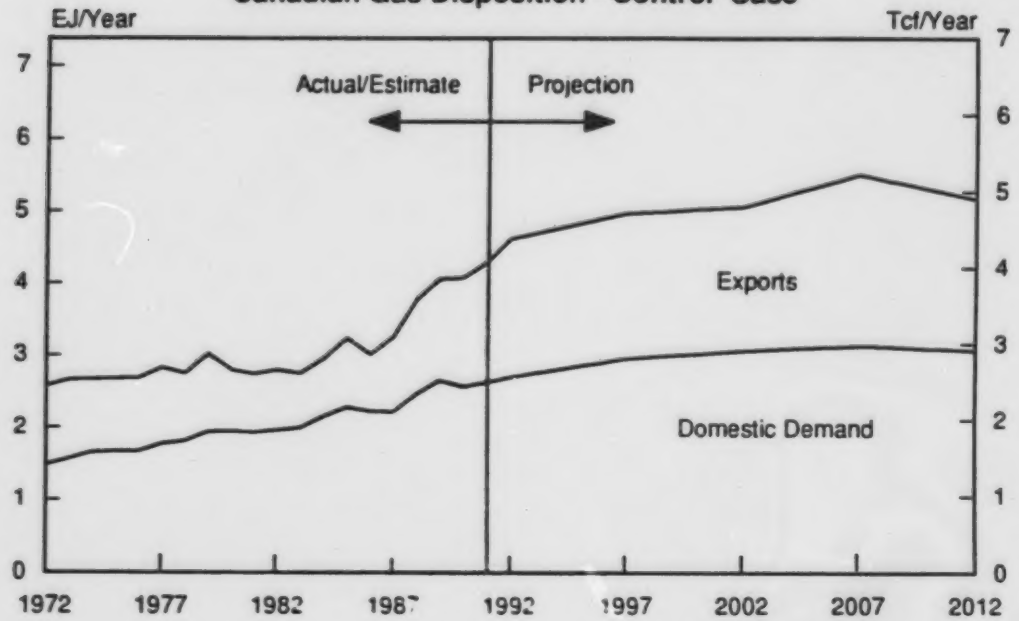


Table 3-3
Canadian End-Use Prices - 1991$ U.S./Mcf

	1992	1997	2002	2007	2012
Core -Gas	3.94	4.59	5.29	5.94	6.74
Non-Core					
-Gas	3.08	3.73	4.43	5.05	5.87
-HFO	3.59	4.04	4.34	4.64	5.01
-Gas/HFO	.86	.92	1.02	1.09	1.17

3.1.6 Canadian Domestic Demand

Overall, Canadian domestic demand grows at 1.2% per year during 1992-2002 then remains about stable in the subsequent 10-year period.

On an end-use basis, the core market maintains moderate growth through the entire period (Figure 3-7). The non-core market continues to grow in the near term. Eventually, substitution by HFO causes Canadian non-core gas volumes to decline.

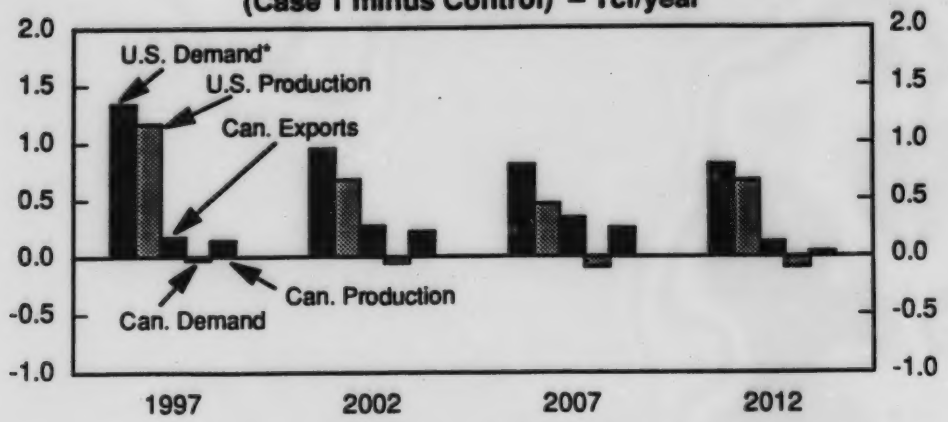
On a regional basis, gas demand in Western Canada grows during the entire period whereas, due to the price disadvantage relative to HFO, demand actually declines in Ontario (post-2002) and Quebec (post-1992). The actual extent of HFO substitution could be much less, depending on the capability of industrial users to switch and possibly, the extent to which consumers would be willing to pay a premium for gas.

3.1.7 Canadian Production

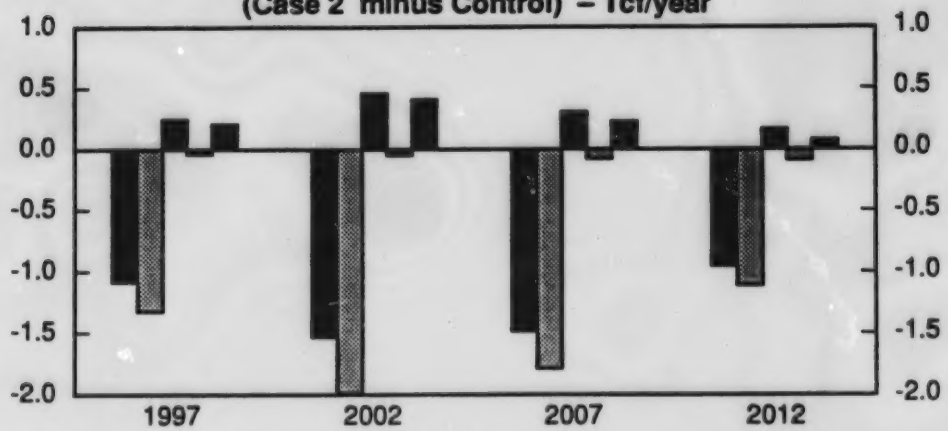
Reflecting the combined increase in Canadian domestic demand and exports, production increases from about 4 Tcf/y currently to close to 5 Tcf/y after the turn of the century (Figure 3-8). Most WCSB production continues to be met from Alberta supplies. Mackenzie Delta production commences in 2004, with volumes growing to about .7 Tcf/y.

Figure 3-9

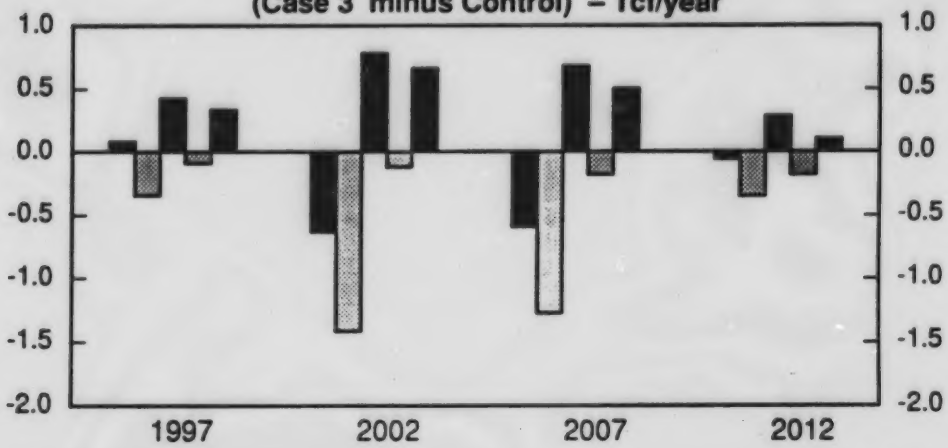
Higher U.S. Demand Impact
(Case 1 minus Control) – Tcf/year



Higher U.S. Costs Impact
(Case 2 minus Control) – Tcf/year



Combined Impact
(Case 3 minus Control) – Tcf/year



* The impact on U.S. demand includes the net effect of the initial (10%) increase and the reduction in demand caused by higher gas prices.

3.2 Impact Cases

As noted in Chapter 2, two different types of circumstances that could lead to higher exports have been assessed. Compared to the Control Case, the first case assumes a 10% increase in U.S. gas demand and the second assumes a 25% increase in U.S. gas supply costs[1]. A third case results from combining the first two. The analysis traces the effects of these initial stimuli through both the U.S. and Canadian markets.

3.2.1 Overview

The impacts on U.S. and Canadian demand and production, compared to Control case levels, are summarized in the three panels of Figure 3-9.

Case 1 - Higher U.S. Demand[2]

Higher U.S. demand causes both U.S. production and Canadian exports to increase. Because higher cost supplies are accessed sooner - compared to the Control case - the requirement for these supplies results in upward price pressure. Higher prices feed back to U.S. demand, reducing the initial stimulus. However, U.S. demand is still higher than the Control case. While higher prices reduce Canadian demand, the net effect on Canadian production (with higher exports) is positive.

The U.S. demand impact is dampened over time because higher prices, resulting from higher cost supplies, cause conservation and fuel-switching. Later in the period, the impact on Canadian exports lessens when increasing Canadian supply costs, associated with higher production levels, result in N. Alaskan gas and LNG imports becoming more attractive.

Case 2 - Higher U.S. Costs

Higher costs reduce the competitiveness of U.S. gas vis à vis Canadian supplies; hence, Canadian exports increase. The effect of higher U.S. costs and higher level of Canadian exports is to increase market prices, which in turn reduces both U.S. and Canadian demand. Higher exports more than offset the reduction in Canadian domestic demand, resulting in a net increase in Canadian production.

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1. These impacts are phased in to their target levels during 1993-1997 and are maintained at these levels for the remainder of the study period.

2. In the following sections the case numbers, e.g., "Case 1" and their descriptions, eg, "Higher U.S. Demand" will be used interchangeably.

Figure 3-10
Canadian Gas Exports

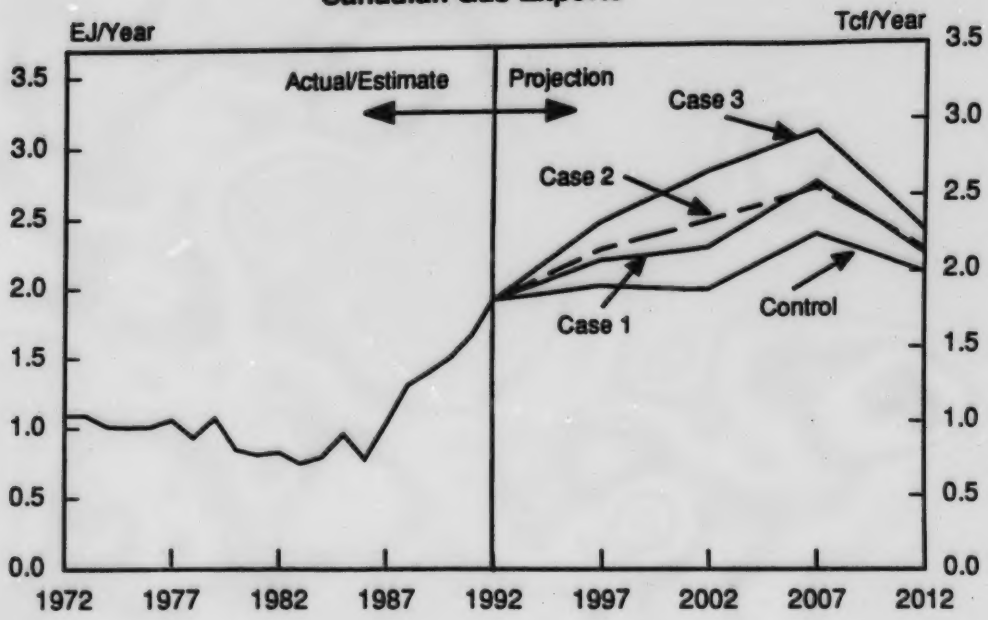
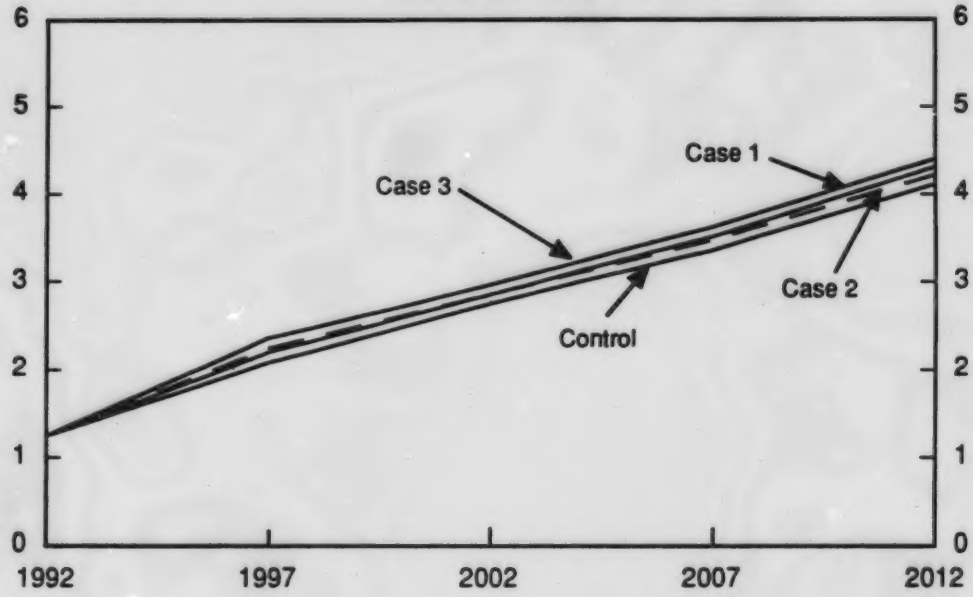


Figure 3-11
Alberta Fieldgate Gas Price
1991$ U.S./Mcf



Case 3 - Combined Case

In the U.S., the effect of higher demand is more than offset by higher costs, i.e., both demand and production tend to be lower than the Control case. In Canada, the positive impact of higher U.S. demand on exports and production volumes is reinforced by higher U.S. costs.

3.2.2 Canadian Gas Exports

The gas export projections are illustrated in Figure 3-10. In Case 1, exports rise gradually from 1.8 Tcf in 1992 to 2.5 Tcf in 2007 and then decline to 2.1 Tcf by the end of the study period. The decline after 2007 corresponds to the start-up of N. Alaskan gas and increased competitiveness of LNG.

In Case 2, exports also peak at 2.5 Tcf in 2007 before declining in the subsequent 5-year period. Volumes are initially higher than Case 1, then similar to it later in the projection period.

In Case 3, the effects of higher U.S. demand and higher gas supply costs are reinforced. Exports rise steadily to a peak of 2.9 Tcf/y in 2007 before declining to about 2.3 Tcf/y.

Table 3-4
Canadian Gas Exports (Net)

	1993-2012		
	Annual Average Tcf/y	Total Tcf	Total vs. Control Tcf
Control	2.0	40	-
Case 1	2.2	44	4
Case 2	2.3	46	6
Case 3	2.5	50	10

3.2.3 Canadian Fieldgate Prices

The effect of higher U.S. gas demand and higher U.S. costs is to increase Canadian exports and thereby bring forward in time the requirement to access higher cost Canadian gas supplies.

As Table 3-5 illustrates, the impact on fieldgate prices in Case 1 and Case 2 is much the same. Relative to Control case levels wellhead prices in Case 1 and Case 2 are higher by 3-8%, whereas in Case 3 prices are higher by 7-13%.

In our analysis, the Canadian fieldgate price effects reflect the outcome of events initiated in the U.S. market. Hence, U.S. producers experience similar price effects.

Figure 3-12
Canadian Gas Demand
Core Market

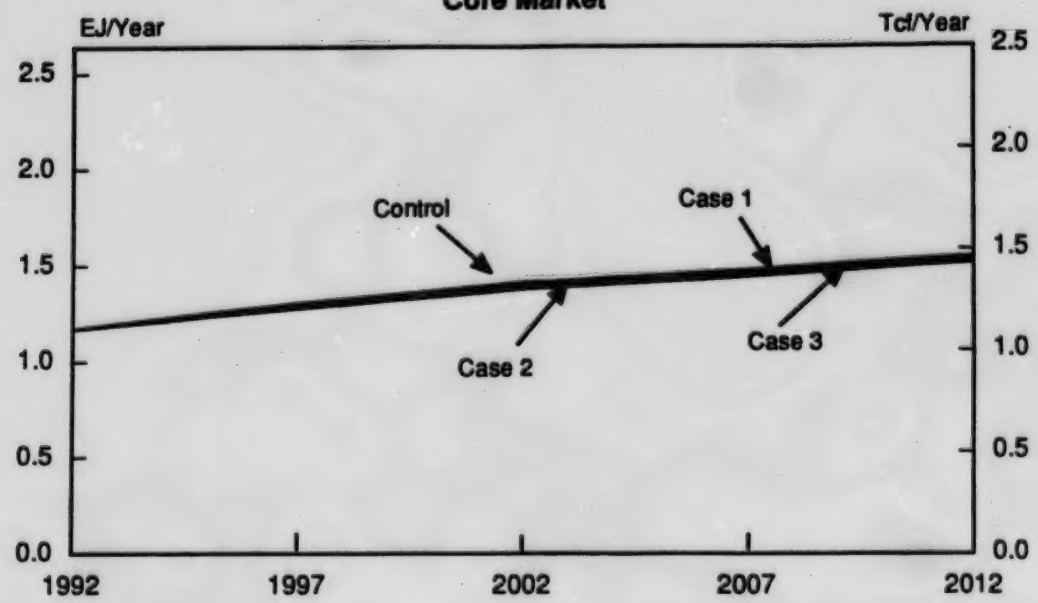


Figure 3-13
Canadian Gas Demand
Non-Core Market

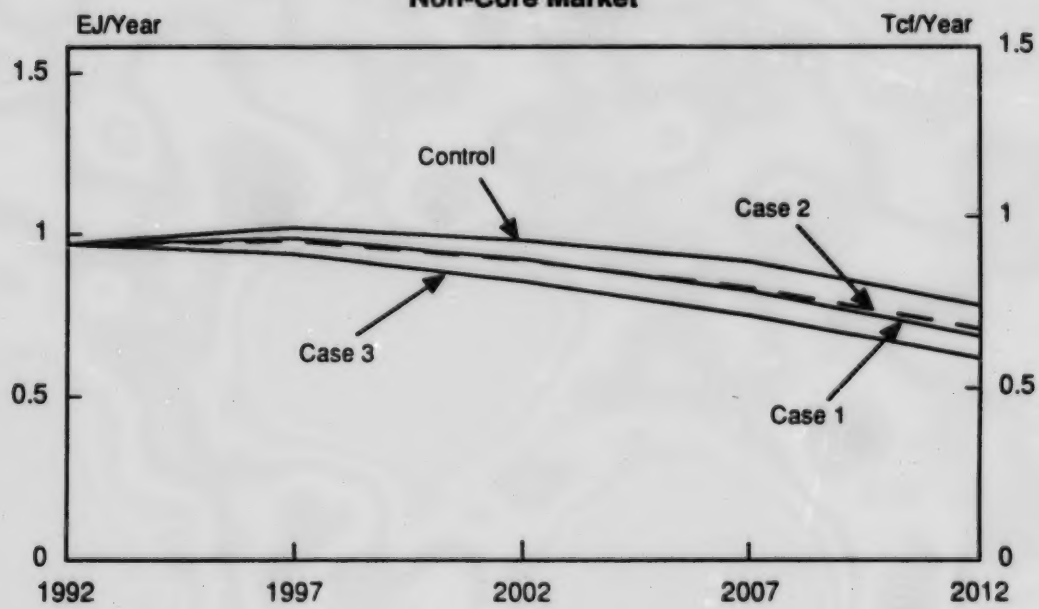


Table 3-5
Alberta Fieldgate Prices

	1992	1997	2002	2007	2012
		1991$ U.S./Mcf			
Control	1.24	2.07	2.75	3.36	4.11
		Ratio to Control Case			
Case 1	1.0	1.06	1.04	1.05	1.05
Case 2	1.0	1.08	1.04	1.03	1.03
Case 3	1.0	1.13	1.08	1.08	1.07

3.2.4 Canadian Consumer Prices and Demand

In our impact cases the price of oil is assumed to remain unchanged from the Control case. Thus the effect of higher gas prices is to erode the competitive position of gas relative to oil. This is most evident in the non-core market where fuel switching is assumed to be possible. Because there is little near-term capability to substitute fuels in the core market, gas consumption can only be reduced by the "conservation effect" of higher prices.

Average core market prices in Cases 1 and 2 are 2-4% above Control case levels. In Case 3, prices are 4% to 6% higher. In absolute terms, the price increase at the burner tip is the same as experienced by producers. In percentage terms, the consumer increase is smaller because the transmission and local distribution components of the end-use price are assumed not to change.

Table 3-6
Canadian Gas Prices
Core Market

	1992	1997	2002	2007	2012
		1991$ U.S./Mcf			
Control	3.94	4.59	5.29	5.94	6.74
		Ratio to Control Case			
Case 1	1.0	1.03	1.02	1.03	1.03
Case 2	1.0	1.04	1.02	1.02	1.02
Case 3	1.0	1.06	1.05	1.05	1.04

Gas price increases in the non-core market are the same as those in the core market. However, to the extent that HFO substitution is

Figure 3-14
Canadian Gas Demand
(excl. Reproc.)

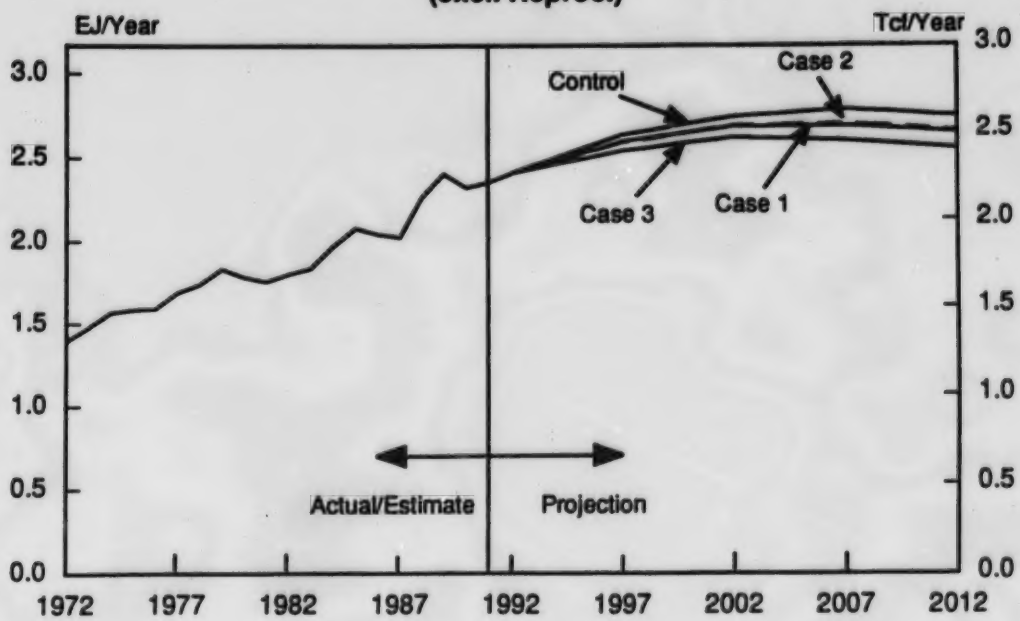
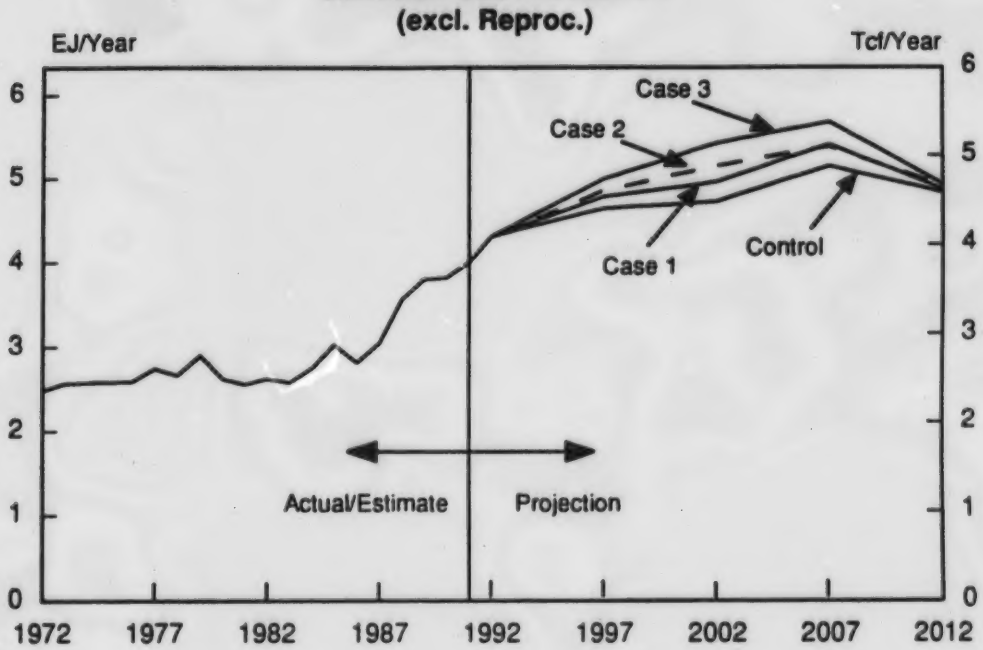


Figure 3-15
Canadian Gas Production
(excl. Reproc.)



possible, the significant factor for non-core gas consumption is the change in the price of gas relative to HFO. The higher gas prices in the impact cases cause the competitive position of gas relative to HFO to deteriorate relative to the Control case (Table 3-5).

Table 3-7
Canadian Gas Prices
Non-Core Market

	1992	1997	2002	2007	2012
		Ratio to HFO			
Control	.86	.92	1.02	1.09	1.17
Case 1		.95	1.05	1.12	1.21
Case 2		.96	1.04	1.11	1.19
Case 3		.99	1.07	1.15	1.23

Figures 3-12 and 3-13 provide a perspective on demand impacts. Core demand is only slightly negatively affected by the higher prices of the impact cases. The reduction in non-core demand in both Case 1 and Case 2 is about 7 % (50 Bcf/y) by 2002, and about 14 % (100 Bcf/y) in Case 3. While significant with respect to the non-core market, and increasing over time, the reduction is small relative to total demand.

Canadian Domestic Demand (Figure 3-14) is reduced in all impact cases, primarily due to the effect of higher gas prices on non-core demand. In 2002, Case 1 and Case 2 are lower by 2-3% while Case 3 is lower by about 5%. By the end of the study period the annual reduction is 3-4% in Case 1 and Case 2 and 7% in Case 3.

3.2.5 Canadian Production

Over the 20-year period to 2012 the incremental annual production in the impact cases is 4-9% higher than the Control Case. Total incremental production over the period would be in the range of 3-8 Tcf (Table 3-8). Annual trends are illustrated in Figure 3-15.

Table 3-8
Canadian Gas Production
(excluding Reprocessing)
1993-2012

	Average Tcf/y	Total Tcf	Total vs. Control Tcf
Control	4.5	91	-
Case 1	4.7	94	3
Case 2	4.8	95	4
Case 3	4.9	99	8

Figure 3-16
Ontario Gas Demand
Control Case

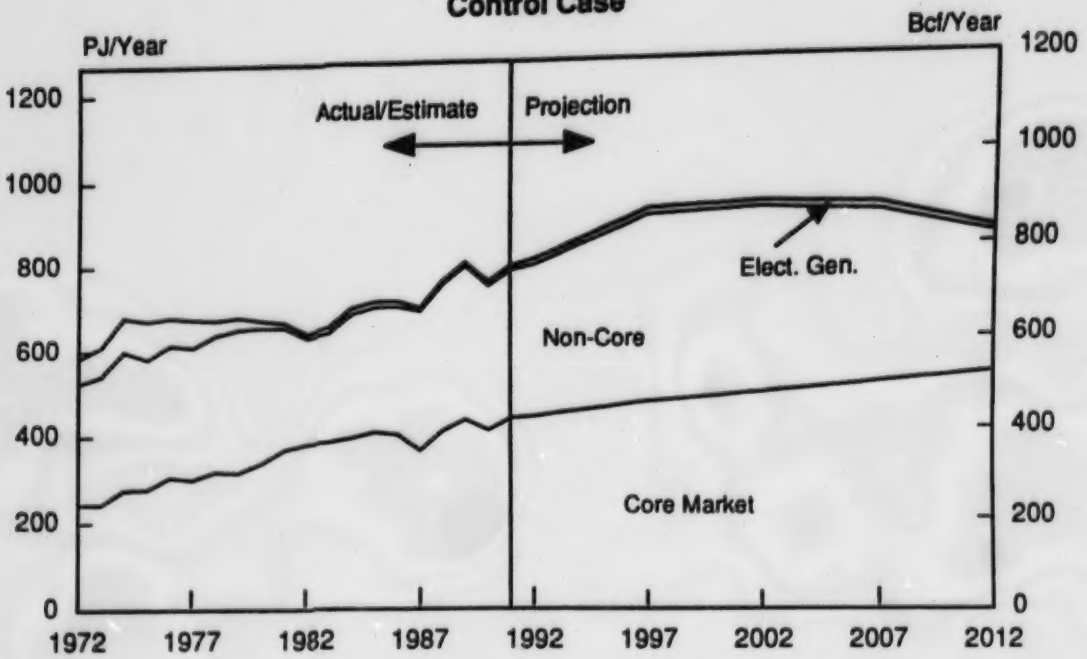
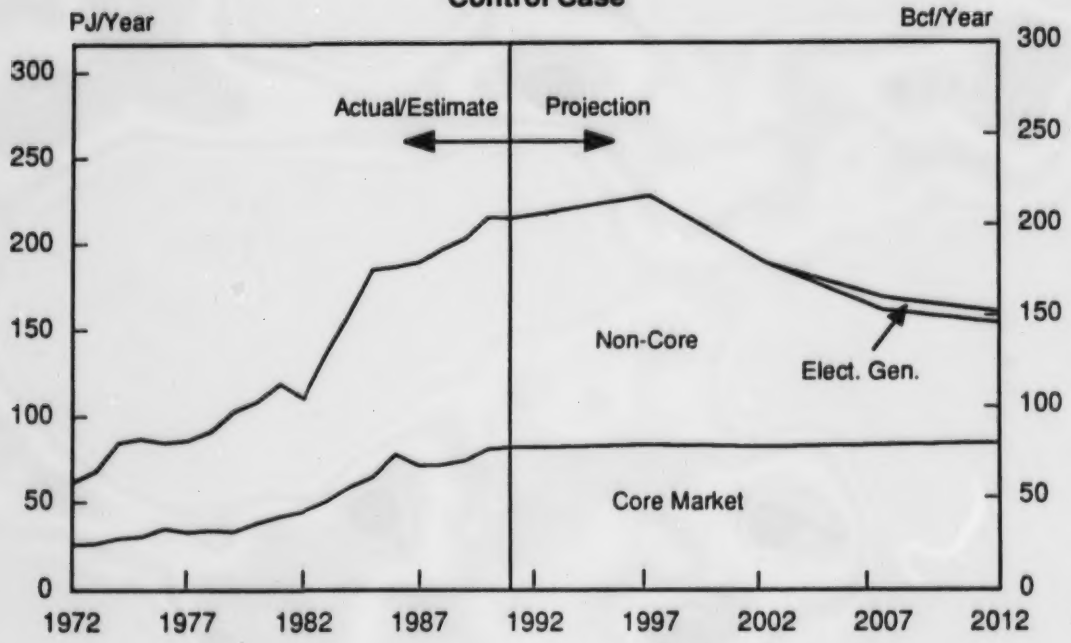


Figure 3-17
Quebec Gas Demand
Control Case



3.2.6 Regional Impacts - Ontario and Quebec

In this section, some of the regional implications of additional gas exports are addressed. Ontario and Quebec are the focus, because these two areas experience a volume reduction which is more than proportional to their share of the Canadian gas market. In the Control Case, Ontario and Quebec constitute about 45-50% of the Canadian end-use market over the next 10-15 years (end-use projections in Figures 3-16 and 3-17). However, when comparing the Control case with Case 3, they absorb 55-65% of the Canadian demand reduction.

Core Market

Core market demand grows over time and is little affected by the higher prices of the impact cases. As noted earlier, the core market has limited ability to substitute between fuels. Moreover, gas delivered to the core market remains favourably priced relative to LFO and electricity.

Delivered gas prices to Ontario and Quebec reflect increasing real wellhead prices plus transmission and distribution costs (the latter are assumed to remain constant in real terms). Price effects in the two regions are quite similar. In Case 1 and Case 2, core market prices are 1-3% above the Control Case. Prices are 4-6% higher in Case 3.

Table 3-9
Core Market Gas Prices

	1992	1997	2002	2007	2012
	Ontario - 1991$ U.S./Mcf				
Control	4.50	5.20	5.96	6.64	7.49
	Ratio to Control Case				
Case 1	1.0	1.03	1.02	1.03	1.03
Case 2	1.0	1.03	1.02	1.02	1.02
Case 3	1.0	1.06	1.04	1.05	1.04
	Quebec - 1991$ U.S./Mcf				
Control	5.51	6.25	7.05	7.77	8.67
	Ratio to Control Case				
Case 1	1.0	1.02	1.02	1.02	1.02
Case 2	1.0	1.03	1.02	1.02	1.01
Case 3	1.0	1.05	1.04	1.04	1.04

Figure 3-18
Ontario Non-Core Gas Prices
1991$ U.S./Mcf

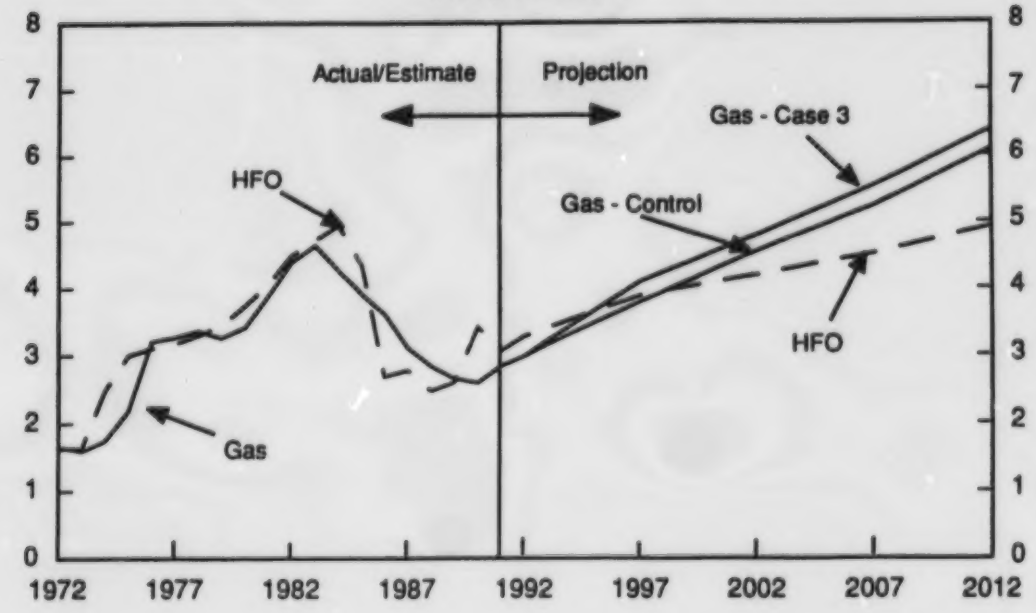
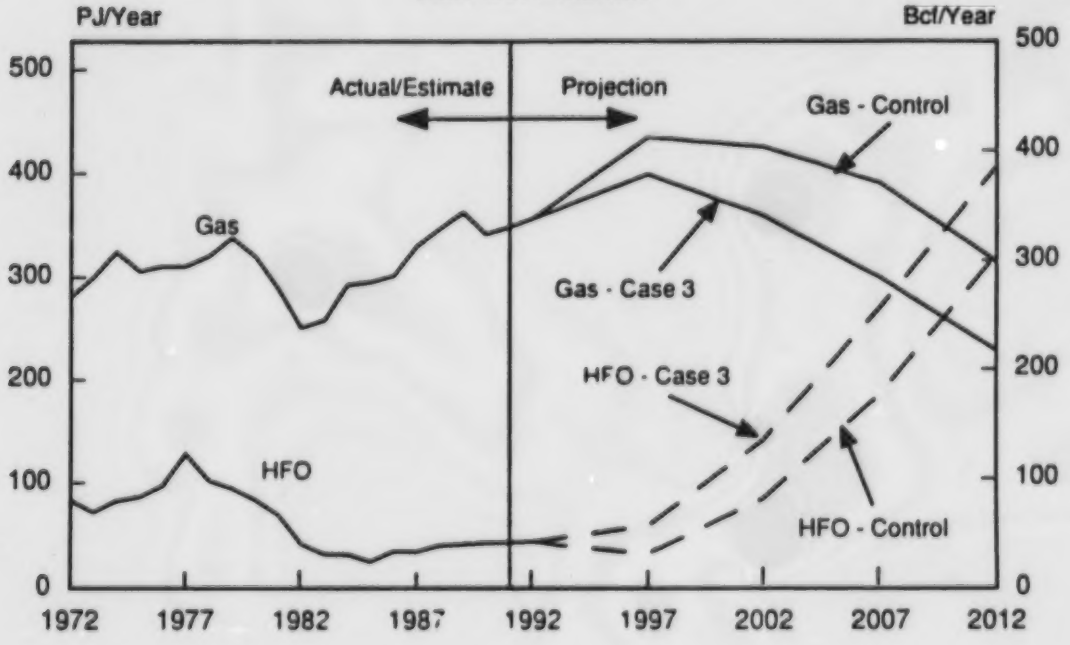


Figure 3-19
Ontario Gas Demand
Non-Core Market



Non-Core Market

In the non-core market, because it was assumed there would be substantial fuel-switching capability, gas loses market to HFO when gas prices increase relative to HFO. In the Control Case, non-core gas prices in Ontario reach parity with and surpass HFO prices in the 1997-2002 time frame (Figure 3-18). Parity in Quebec is more imminent, occurring in the 1992-1997 period (Figure 3-20). Even though it was assumed that switchable consumers will continue to use gas at prices above parity with HFO, because of its handling and burning characteristics (in effect, paying a premium for gas), continually rising prices still cause a very large loss of market share to HFO.

Substitution by HFO would be a reversal of the trend over the past 15-20 years during which industrial gas consumption increased while HFO decreased. In the Control Case, Ontario's HFO consumption would reach the peak levels of late-1970s in the 2002-2007 time period (Figure 3-19). This "threshold" would be advanced by 3-4 years in Case 3 (to 1997-2002) and somewhat less in Cases 1 and 2. In Quebec, the peak level of HFO consumption of the early-1970s would also be re-attained in 2002-2007 time frame (Figure 3-21). The timing would be somewhat advanced in the impact cases.

As gas prices continue to rise relative to oil prices the fuel switching assumptions used in this analysis result in a continued increase in HFO use. Because a similar result occurs in the U.S., which accounts for a substantial portion of world oil demand, this could place upward pressure on oil prices. This calls into question the validity of the assumption that oil prices are exogenous to the analysis. This matter and the more general issue of the feasibility of HFO substitution are addressed in Section 3.3.

Figure 3-20
Quebec Non-Core Gas Prices
1991$ U.S./Mcf

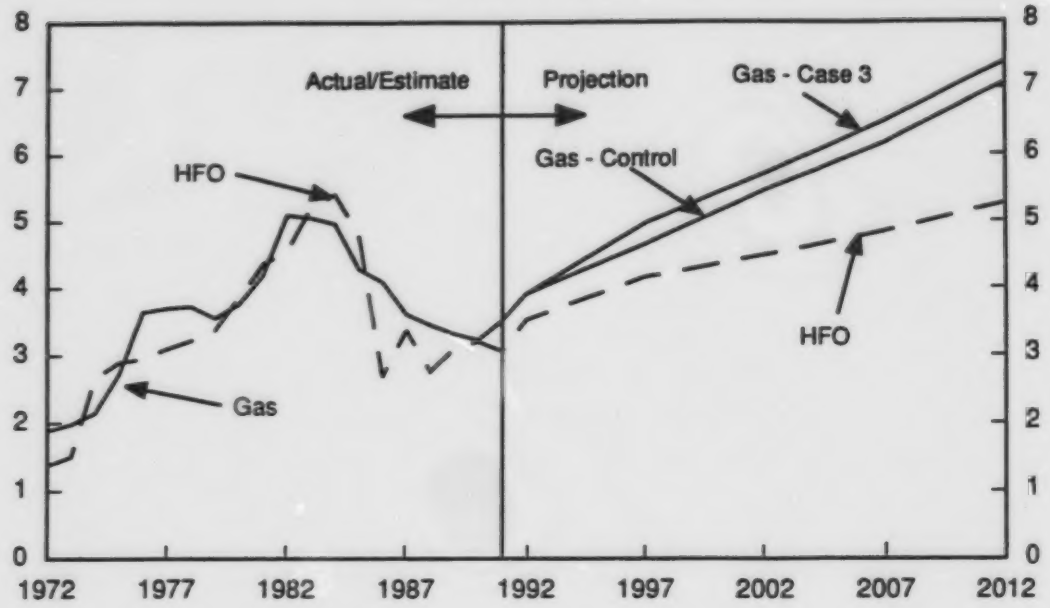
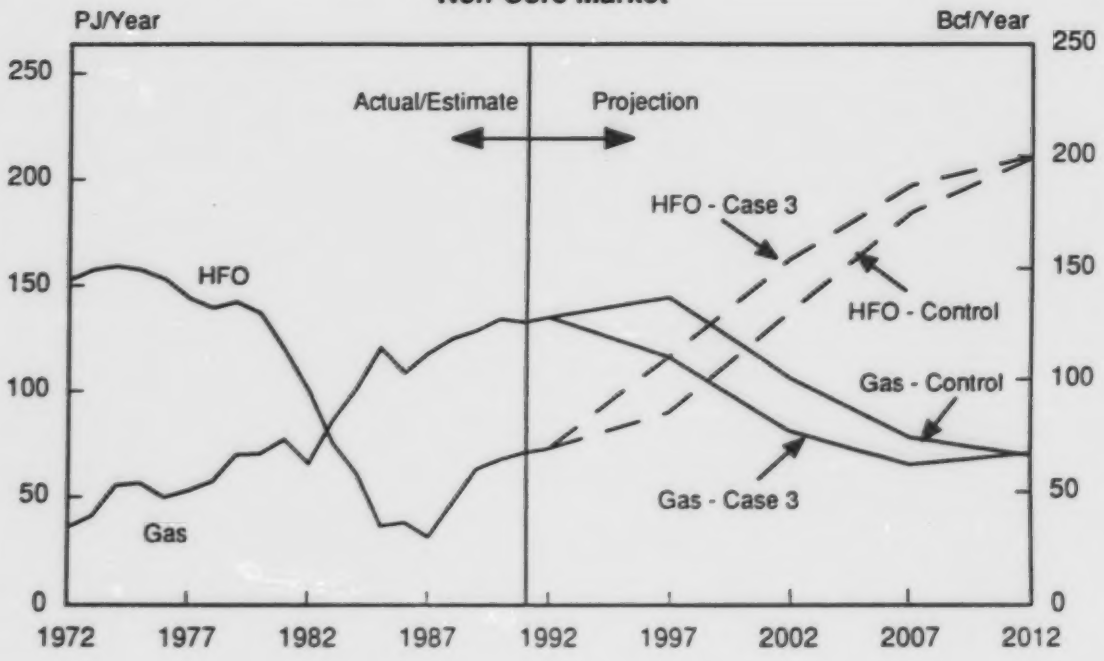


Figure 3-21
Quebec Gas Demand
Non-Core Market



3.3 Demand Adjustments

The analysis indicates that the impact on core market prices and volumes, which result from the market conditions assumed in the impact cases, would be modest.

With respect to the non-core market however, given the assumptions, there would be a large reduction in gas demand as HFO is substituted for gas. Figure 3-19 (Ontario) and Figure 3-21 (Quebec) illustrate the magnitude of this substitution. As previously indicated, this would mark a reversal in the gas-to-oil substitution witnessed over the past 15-20 years. There are a number of reasons why the substitution of HFO for gas may not occur, or at least not to the extent indicated.

(a) Exogenous Oil Price Assumption

An important exogenous (or externally-derived) variable which enters this analysis of gas markets is the price of crude oil. The oil price projection and the prices for petroleum products, including HFO, are determined for a particular scenario and are not modified by the outcome of the scenario.

However, the amount of switching to HFO in the projections, in both Canada and the U.S., is quite substantial. In 2002, when comparing Case 3 with the Control Case, the amount of switching in Canada is about.1 Tcf/y and about 2.3 Tcf/y in the U.S. The total is the equivalent of about 1.2 MMb/d of HFO. This would increase North American import requirements and could put pressure on the world demand for HFO, and therefore on the demand for crude oil. Thus a large amount of HFO substitution - as the result of rising gas prices - suggests that some type of market adjustment, such as higher HFO prices, may occur to offset or mitigate the extent of this fuel substitution.

Exogeneity of oil prices is particularly relevant when assessing volume effects relative to the Control Case. The higher gas prices in the impact cases, assuming oil prices do not change, accelerate HFO substitution.

(b) Infrastructure

Fuel switching of the magnitude implied by the analysis appears to imply substantial investment in the transportation (or logistical) infrastructure, particularly with respect to Ontario. The costs of such investment have not been assessed. It may be the case that the resultant higher costs of such investments would reduce the competitiveness of HFO relative to gas in the Ontario market.

Figure 3-22
Productive Capacity of Natural Gas

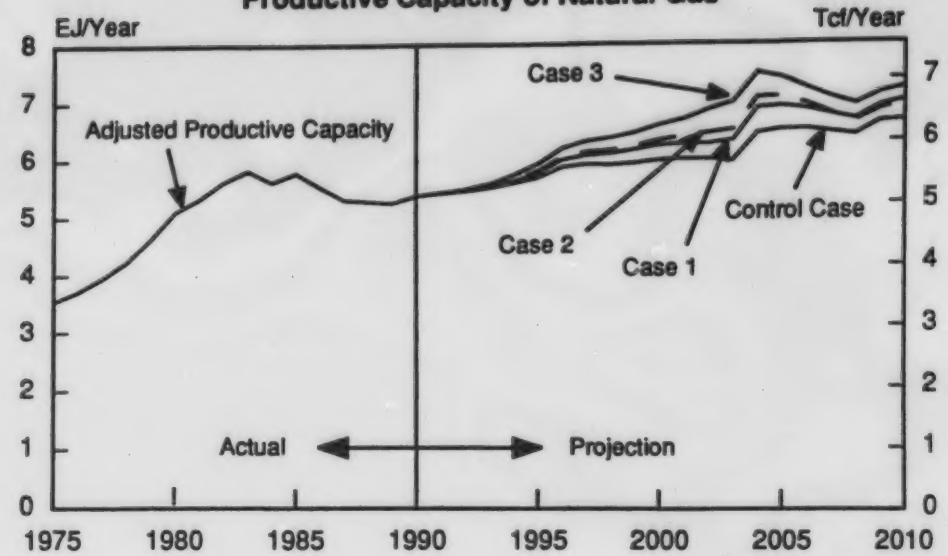
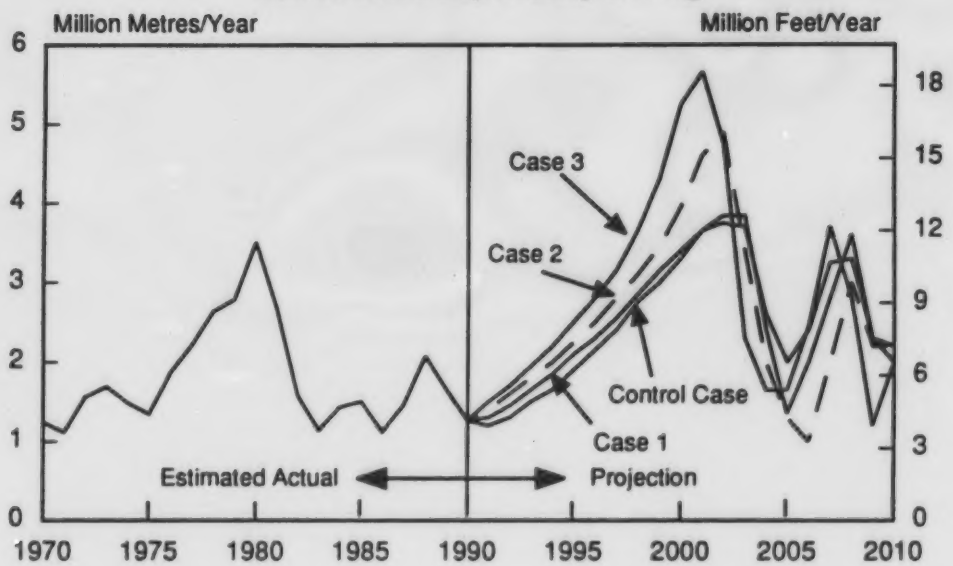


Figure 3-23
Gas Directed Exploratory Drilling



(c) Restrictions on HFO Use

Limitations on HFO consumption could be imposed for environmental reasons. The price of HFO would have to be factored upward to account for emissions mitigation measures or dilution of HFO with cleaner-burning light products. This could result in a higher premium on the use of gas than was assumed, and hence less substitution of HFO for gas.

(d) Alternatives to HFO

Alternatives such as electricity or clean coal technology may become available to replace some or all of the demand for HFO. While electricity has an apparent price disadvantage, it has been made available on a competitive basis in the Quebec industrial market. Introduction of clean coal technology in this time frame and its applicability are uncertain.

In summary, the validity of our assumptions about gas/HFO switchability in industrial markets is questionable and further analysis appears to be needed.

3.4 Supply Adjustments

Higher gas exports and therefore higher Canadian production levels require that additional productive capacity be developed. Deliverability projections are dependent on estimates of resource base, reserve additions and rates at which reserves can be produced. There is considerable uncertainty associated with the outlook for each of these variables. This uncertainty should be borne in mind when considering the deliverability projections.

Figure 3-22 illustrates the results for productive capacity from the WCSB and frontier regions in the Control and impact cases. Capacity expands in line with the demand requirements in each case[1]. In all cases, Mackenzie Delta gas commences to flow in 2004.

Figure 3-23 illustrates industry exploration activity in the WCSB, as measured by annual metres drilled. Each curve represents the implied level of activity required to add the necessary reserves consistent with the respective deliverability projection. In the Control Case, near-term activity is relatively low, reflecting the current gas supply surplus. Drilling increases later in the 1990s as demand picks up and the surplus erodes. In the late-1990s, activity approaches the historically-high levels of the late-1970s and early-1980s. Activity peaks around 2002 and then declines due

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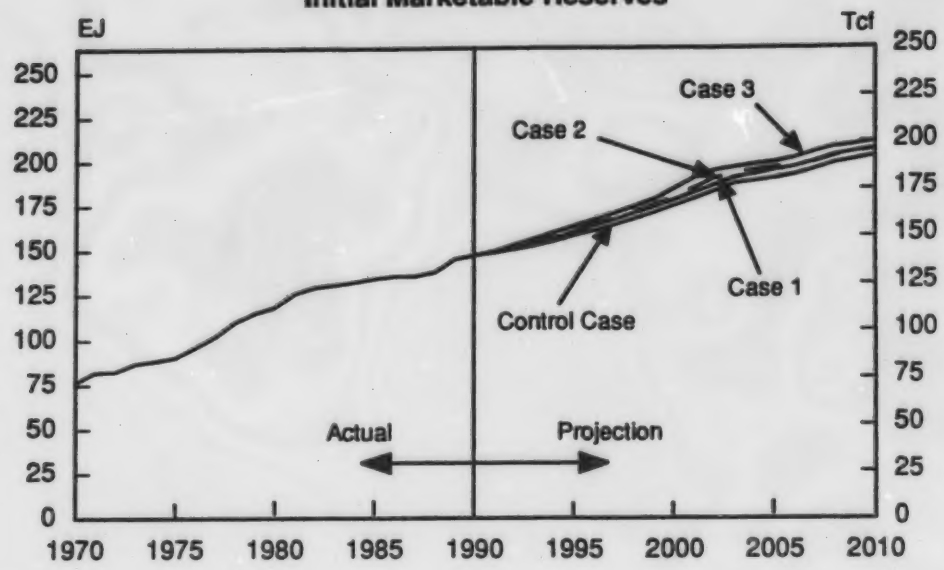
1. Productive capacity is higher than production by as much as 10-15% to allow for peak-day requirements and other operational considerations.

Figure 3-24
Initial Marketable Reserves



to the onset of production from the Mackenzie Delta. WCSB activity then recovers as demand continues to grow and the Delta volumes are absorbed. A second cycle, peaking around 2007, corresponds to the onset of additional frontier production toward the end of the study period (Venture Project and additional N. Canada).

Compared to the Control Case, the higher demands in the impact cases cause significantly higher near-term activity. In addition, activity peaks at higher levels and 2-3 years earlier. For example, the Case 3 peak occurs around the year 2000 at a level of drilling about 50 % higher than the Control Case.

The capacity projections in the Control Case and impact cases are based on an ultimate potential of gas reserves in the WCSB of 250 EJ (237 Tcf). The estimate of the amount of these reserves that will have been discovered by the end of the study period ranges from about 203 EJ in the Control Case to 211 EJ in Case 3 (Figure 3-24).

The greatly increased levels of activity which are suggested by the analysis may be offset by a number of factors which may affect the rate of reserves additions. These include: a larger estimate of the ultimate potential of gas reserves which would serve to slow the decline of the reserves found per metre of drilling; the impact of new exploration technology which enables explorers to find greater amounts of new reserves in known fields and new prospects; and, improved production methods which enable increased recovery. If these improvements were to occur, the amount of new exploratory drilling required to satisfy the increased exports could be reduced considerably.

Table 3-10
Comparison of Impacts
1992 EIA vs 1989 EIA
% Change Compared to Base[1]

	1997[2]	2002	2007
		Canadian Gas Exports	
1992 EIA	9-22	15-41	15-30
1989 EIA	38	38	38
		Canadian Domestic Demand	
1992 EIA	<2-5>	<3-7>	<4-8>
1989 EIA	<3>	<3>	<4>
		Canadian Production Volumes	
1992 EIA	3-8	5-15	5-10
1989 EIA	12	11	10
		Ontario: Core Market Prices[3]	
1992 EIA	2-6	2-4	2-5
1989 EIA	13	9	14
		Ontario: Non-Core Prices[4]	
1992 EIA	3-8	3-5	3-6
1989 EIA	0	0	0
		Quebec: Core Market Prices[3]	
1992 EIA	2-5	2-4	2-4
1989 EIA	13	9	14
		Quebec: Non-Core Prices[4]	
1992 EIA	3-7	2-5	2-5
1989 EIA	0	0	0

Notes
1. The range in the 1992 EIA reflects three impact cases compared to the Control Case. The impacts in the 1989 EIA are based on incremental annual exports of about 500 PJ compared to the 1988 Supply/Demand report Low Oil Price Case (Average Resource Scenario).
2. Years used for the 1989 EIA are 1995, 2000 and 2005.
3. The 1989 EIA is represented by Residential sector prices.
4. In the 1989 EIA, it was assumed that gas prices would remain competitive with HFO in the industrial sector, so that a general increase in gas prices would be absorbed by residential and commercial consumers.

3.5 The Board's Second EIA(1992) Compared to the First EIA(1989)

The approach taken in the 1992 EIA is different from that in the 1989 EIA. The basic difference is that a general equilibrium (GE) approach was used in the 1992 EIA, which takes into account the integrated nature of the U.S. and Canadian gas markets.

Using the GE approach, additional Canadian exports are the outcome of changes in fundamental factors that could cause these exports to occur. The two factors examined are higher U.S. demand and higher U.S. gas supply costs. In addition, the approach recognizes that offsetting forces can occur to moderate these initial stimuli. In the 1989 EIA, the incremental export level was "assumed", without regard to specific causality, and the impact was assessed entirely in the context of the Canadian market.

The results of the current analysis are compared with the 1989 EIA in the following comments. Table 3-10 indicates differences in impacts on some selected indicators.

- The export volume impact is smaller in the 1992 EIA primarily because the base level of exports is higher (2.0 Tcf/y compared to 1.4 Tcf/y).

- The reduction in domestic demand is higher because of the sensitivity of the non-core market to price. In the 1989 EIA, non-core gas prices remained competitive with HFO to maintain market share.

- On balance, the impact on production volumes is comparable, although the absolute production volume of the 1992 EIA base case is higher (due to higher exports as indicated above).

- With respect to consumer prices, the impact is less in the core market and greater in the non-core market. In the 1989 EIA price impacts were absorbed by the residential and commercial consumers by price "streaming". Industrial gas prices did not change with the overall increase in gas prices so as to remain competitive with HFO. In the 1992 EIA, price changes are dispersed over the entire end-use market.

Chapter 4 Preliminary Conclusions and Issues

This EIA is based on the assumptions underlying the Board's 1991 report entitled *Canadian Energy Supply and Demand 1990-2010*. That report includes projections of a range of outcomes for natural gas demand, supply and prices, based on changes in key assumptions. This analysis addresses three additional cases that could specifically lead to higher Canadian natural gas exports.

The first two cases assume higher U.S. demand and higher U.S. gas supply costs respectively, relative to the Control Case. A third case combines the assumptions of the first two. The impact of additional exports on Canadian prices and volumes is assessed in a general equilibrium framework of the North American gas market, which recognizes the integrated nature of Canadian and U.S. gas flows and natural gas price determination. The analysis covers the period 1992-2012.

Based on the assumptions, the analysis suggests a number of preliminary conclusions:

- natural gas exports average 2.2-2.5 Tcf/y over the study period depending on the impact case. This compares to Control Case exports of 2.0 Tcf/y.

- Canadian wellhead gas prices increase (relative to Control) by 3-13 % in any given year. Increases to Canadian consumers are in the range of 2-6 % in the core market and 3-7% in the non-core market. Because of the integrated nature of the Canadian and U.S. markets, these price effects would be similar to those experienced by U.S. producers and consumers.

- Canadian domestic demand is somewhat reduced by higher prices. The volume reduction is borne mostly by non-core (industrial) consumers, who have the capability to switch to HFO when gas prices rise relative to oil. The core market (residential, commercial) is relatively insensitive to price changes.

- Canadian production (excluding reprocessing shrinkage) is higher by .2-.4 Tcf/y over the study period, averaging 4.7-4.9 Tcf/y in the impact cases relative to 4.5 Tcf/y in the Control Case. Production peaks in 2007 in the range of 5.1-5.4 Tcf in the impact cases and 4.9 Tcf in the Control Case. In all cases, including the Control Case, Mackenzie Delta

gas flows beginning in 2004 and, by the end of the study period, contributes about .7 Tcf/y to supply.

Overall, the impacts of higher exports on Canadian prices and domestic consumption are not large.

Allowing for the differences in assumptions and approach, the overall impacts on domestic volumes and prices are similar to those in the 1989 EIA.

However, there are a number of issues pertaining to the magnitude and feasibility of demand-side and supply-side adjustments.

On the demand side:

The projections indicate that there would be significant switching to HFO from gas due to rising gas prices. This would be a reversal of the trend of the past 15-20 years. It is questionable whether the estimated amount of substitution is feasible. This also raises the question as to whether other adjustments might occur, such as:

- higher HFO prices resulting from increased demand for HFO, or higher costs associated with investments in transportation infrastructure, thus modifying the extent of HFO substitution;

- restrictions on HFO use, resulting from environmental considerations;

- availability of other alternative fuels.

Given these potential occurrences it is not clear that fuel switching would occur to the extent indicated in this analysis.

On the supply side:

The increased gas exports place additional demand on the productive capacity of the WCSB. To meet this demand the analysis indicates that exploration activity will have to increase rapidly in the mid-1990s to levels which exceed previous peak drilling levels by a large margin. However, several years of lead-time are available for the drilling industry to rebuild the equipment and expertise, and the acceleration in activity is comparable to the rapid increases which were observed during the period from 1975 to 1981.

In addition, the exploitation of new exploration technology, improved production methods and increased understanding of the geology and resource potential in the WCSB could result in a more effective exploration and development effort. The extent to which these trends occur will moderate the acceleration in required activity over time.

The timing of Mackenzie Delta and N. Alaskan production in the analysis is governed by relative costs compared to the WCSB (and the U.S. Lower-48). The timing and feasibility of frontier production are questionable.

Natural Gas Price Outlook

The approach to natural gas pricing is based on a long-term view of rising natural gas supply costs. This is a common approach and is supported by much empirical work in Canada and U.S. However, there is an emerging view that future gas supply costs will not increase (in real terms) to the extent that was thought, say, two or three years ago. This implies, for example, either that technological improvements will continue to be made or that estimates of resource base will continue to grow, thus moderating cost increases.

Consultation with Interested Parties

This draft EIA provides a basis for discussion with interested parties. To help focus that discussion, a set of questions has been developed regarding the approach taken in the analysis and the assumptions. These are included on the following pages.

EIA - List of Questions

The following questions are provided to help stimulate discussion on aspects of the EIA analysis. The list is not necessarily exhaustive, nor is it intended to limit the scope of discussion on the approach to the EIA. The sole purpose of this list is to assist interested parties in the preparation of their comments on this draft.

I. General

The objective is to produce timely Export Impact Assessments as dictated by material changes in the North American natural gas market which will have an impact on Canada's export and domestic natural gas markets.

a. If a number of scenarios are developed to reflect the uncertainty of particular assumptions, how should the Board deal with the potentially wide range in results?

b. How should the Board address the assessment of potential supply and demand adjustment difficulties?

c. Are the estimates of the impacts on the North American natural gas market portrayed in these EIA scenarios reasonable?

d. Having produced the 1989 EIA using a partial equilibrium approach and the 1992 EIA using a general equilibrium approach, are there any comments regarding the appropriateness of using one approach rather than the other, or both approaches in conjunction?

II. Scenarios

The 1992 EIA includes a base case scenario and three impact scenarios.

a. The Control Case for this EIA is based on the Control Case from the Board's 1991 Supply and Demand Report. Is this a reasonable case from which to run impact scenarios? If not, what would be an appropriate alternative base case?

b. In the Control Case, Canadian gas exports reach and maintain a level of 2.0 to 2.3 Tcf over the 1997 to 2012 period. These levels are clearly above currently-authorized long-term export

volumes. Should the Control Case take into account the licensing process by, for example, including only the volumes of current licences, with no presumption of long contracts being renewed?

c. Is a reasonable range of the potential for higher levels of U.S. gas demand and U.S. gas supply costs adequately represented within the three impact scenarios (10% higher demand, 25% higher costs, and a combination of 10% higher demand + 25% higher costs) or is there greater uncertainty regarding these parameters?

III. Expectations of Future Prices

The approach used for the 1992 EIA assumes that producers/resource owners will always be able to anticipate future prices correctly and bring supplies on line accordingly (ie. have perfect foresight). This approach assumes that fluctuations around long-term trends will be modest.

a. In a long-term analysis such as this, is it appropriate to characterize natural gas prices as following a smooth trajectory? Is there an alternative approach that might be more appropriate?

b. Over the long term, is it appropriate to assume that exploration and development activity will be driven only by expectations of future gas prices? Will other considerations such as the current price of gas (ie. cash flow considerations) also have a significant influence on activity? Is there an alternative approach that would address such additional factors?

IV. Gas Supply

In the 1992 EIA, gas supplies are assumed to be produced in a strict order of ascending cost. Advances in technology are assumed to reduce capital and operating costs over time. Frontier gas supplies are assumed to be brought into production as soon as costs become competitive.

a. Is the assumption of production of new gas supplies in strict order of ascending cost too idealized? If so, what would be an appropriate alternative for the sequencing of production?

b. In these EIA scenarios, technological advances are assumed to reduce capital costs by one percent per year to a minimum of 75 percent of the levels projected on the basis of current technology. Similarly, technological advances are assumed to reduce operating costs by the same one percent per year to

a minimum of 65 percent of the levels projected on the basis of current technology. Is this approach to representing advances in technology appropriate? If so, are the assumed rates of reduction in capital and operating costs to account for the impact of technological advances on supply costs reasonable? If not, is there an alternative approach that might be more appropriate?

c. These EIA scenarios involve relatively rapid increases in levels of exploratory drilling activity. What factors, if any, might offset this increase in exploratory drilling activity by yielding higher levels of reserves per unit of drilling activity?

d. These EIA scenarios bring frontier gas supplies into production as soon as the costs of supply and transmission become competitive. What are the factors which might impede development and production of frontier gas supplies and the accompanying transmission facilities? How long might these impediments delay the production of gas from the frontier?

e. These EIA scenarios do not include exports from the U.S. to Mexico and, in a longer term context, do not include exports from Mexico to the U.S. Should there be an allowance made for substantial natural gas trade between the U.S. and Mexico?

V. Pipeline Tolls

In the 1992 EIA, tolls on pipelines are generally assumed to remain constant in real terms on the basis of the assumption that any increased costs associated with expansions will be offset by depreciation.

Is the general assumption of constant real pipeline tolls appropriate? If not, what are the alternatives?

VI. Demand

In the 1992 EIA, gas demand is represented by a core market (residential gas demand + commercial non-cogeneration gas demand), an industrial market (industrial gas and HFO demand excluding cogeneration), an electricity generation market switchable between gas and HFO (UEG gas or HFO-fired steam turbines), and an electricity generation market switchable between gas and LFO (UEG gas or LFO-fired combustion turbines/combined cycle + commercial cogeneration + industrial cogeneration).

a. In this representation, the core market is assumed to be unable to switch to alternate fuels. Given the price projections in our scenarios, how appropriate is this

assumption? To what extent are the various market sectors able to reduce gas or oil demand by means of conservation?

b. In this representation, 25 percent of the industrial gas market is assumed to be unable to switch to HFO to account for direct process applications, sites that are remote from HFO delivery systems, or sites where use of HFO is inconvenient or impractical. Is this assumption of a non-switchable portion of the industrial market appropriate? If so, is the size of this non-switchable component reasonable?

c. In these EIA scenarios, there is an extensive shift from the use of gas to HFO in industrial and electricity generation markets. Is the extent of this switch from gas to HFO reasonable? What impediments exist which would prevent switching from gas to HFO for boiler applications in industrial and electricity generation sectors over the long term? At what price differential, if any, would such impediments be overcome?

Appendix A

Letter dated 7 September 1989 and attachments

Source: Reasons For Decision, Proposed Amendment to Export Impact Assessment Filing Requirements, NEB, November 1989: Appendix II

File No.: 1067-1

Date: 7 September 1989

To: Interested Parties

Re: Proposed Amendment to Export Impact Assessment Filing Requirements

The National Energy Board ("the Board") decided on 3 August 1989 to seek the view of interested parties on a proposed amendment to the impact assessment filing requirements.

In its July 1987 "Review of Natural Gas Surplus Determination Procedures", the Board established an "Export Impact Assessment" (EIA) filing requirement, the purpose of which is "to allow the Board to determine whether a proposed export is likely to cause Canadians difficulty in meeting their energy requirements at fair market prices". (Page 25, attached as Appendix A.) The decision then described the matters which applicants should address in conducting this assessment, without however, prescribing a particular method of implementation.

Two main EIA implementation issues have arisen over the past two years of natural gas export proceedings:

(1) it is difficult to detect or measure substantial impacts of small proposed export volumes, and

(2) there appears to be uncertainty on the part of applicants about how best to satisfy the EIA requirement.

The Board proposes to improve the efficacy of the EIA by addressing these two problems with amended filing requirements and additional guidance to applicants on the conduct of an EIA.

Attached as Appendix B is the Board's draft proposal for amended filing requirements. The intention of this proposal is to limit the preparation of an EIA to those situations in which the assessment is likely to provide useful evidence to assist the Board in satisfying itself that the proposed exports meet the criteria of Section 118 of the NEB Act.

Attached as Appendix C is a Board staff paper titled: "Export Impact Assessment: Illustrative Analysis". The purpose of this paper is to lay out a technical approach for conducting an EIA, and to show the results using two estimates of Western Canadian Sedimentary Basin resources. The paper addresses the price, demand and supply reactions to a large, hypothetical increase of exports and comments on the likely ease or difficulty of these adjustments occurring. The paper is not presented as a Board conclusion about the acceptability of any particular level of exports. It is published only as a technical illustration of one approach to the conduct of an EIA.

The Board welcomes comment on both Appendices B and C to be filed with the Board by September 29, 1989. The Board expects to issue revised EIA filing requirements by early November 1989.

Yours truly,

Louise Meagher
Secretary

Attach(s)

Appendix A to the Board's letter dated 7 September 1989

2) Export Impact Assessment

Applicants for licences to export natural gas will be required to submit an assessment of the impact of their export proposal on Canadian energy and natural gas markets. This impact assessment will be considered at the public hearing convened to examine the application.

The purpose of the impact assessment will be to allow the Board to determine whether a proposed export is likely to cause Canadians difficulty in meeting their energy requirements at fair market prices.

The nature of the export impact assessment, whether quantitative or qualitative, will depend upon the size and significance of the proposed export. The extent and detail of the analysis should be commensurate with the size of the proposed export.

In dealing with the ability of the Canadian gas producing sector to satisfy Canadian needs, given the proposed export, Applicants will be expected to analyze the relevant geological, engineering, economic and institutional factors influencing gas supply. These factors may include the following: exploration and development costs; levels of drilling activity; the trend in reserves additions relative to drilling effort; the size, location and potential production characteristics of gas pools; transportation requirements from wellhead to market and the feasibility of any new transportation facilities required.

In addressing any need for Canadian gas users to adjust their energy consumption patterns by means of energy conservation or switching to alternative fuels, Applicants will be expected to assess the following factors: the scope for additional conservation; the price of gas relative to other energy forms; the fuel-switching capability of Canadian gas users; and any lags in conservation and fuel-switching and the expected costs involved.

Applicants will also be expected to address the impact of their proposed exports on future natural gas prices. Given the uncertainty associated with future values of key factors underlying natural gas supply and demand, such as world oil prices, Applicants will be expected to do the impact assessment using a reasonable range of values for those factors.

The burden of proof will rest with the Applicant to satisfy the Board that the proposed export is surplus. The hearing process will provide all parties with an opportunity to test the Applicant's evidence and to present evidence supporting or opposing the export proposal.

Appendix B to the Board's letter dated 7 September 1989

Revised Export Impact Assessment Filing Requirements

1. All applications for which the annual volume of exports would be sustained at less than 200 PJ per year are exempt from the requirement to file an EIA.

2. For a single hearing which includes more than one application and for which the total of requested exports for all applications in the same proceeding would be sustained at more than 200 PJ per year, either

   (a) the Board will conduct a preliminary EIA, to be issued to parties with the hearing order as information which parties may use as they see fit; the final EIA will be in the Reasons for Decision and will take account of views of parties;

   or

   (b) all applicants will prepare a joint EIA covering the total of requested exports from all of their applications in the same proceeding.

   (Normally, the Board would schedule more than one application in the same proceeding if there were common factors making it sensible to do so - for example all applications underlying one facilities expansion application.)

3. Board staff will periodically issue updates similar to the analytical paper in Appendix C, providing a view of potential market adjustment implications arising from anticipated changes of export volumes.

4. EIA submissions will continue to have the content described in Appendix A.

Appendix C to the Board's letter dated 7 September 1989

Export Impact Assessment: Illustrative Analysis

The purpose of this Board staff paper is to assess the impact on Canadian consumers of additional natural gas exports to the U.S. Since July 1987, the assessment of the impact of additional natural gas exports has been one component of the Board's Market-Based Procedure, used for considering the merits of applications for natural gas export licences. This paper is intended to be informative to participants in the Board's hearings and to stimulate public discussion.

The impact we are assessing has several key components:

1) incremental exports call forth increasingly costly gas supply over time relative to supply costs without the increment;[1]

2) the delivered prices of gas to Canadian consumers increase because of the increased supply cost;[2]

3) consumers either conserve on the use of gas or they switch to other fuels as they become more economic for some users;

4) this conservation and switching entails an adjustment process which may or may not be easy to achieve;

5) development rates of resources are accelerated.

Our analysis measures the extent of each of these reactions to the incremental export. We discuss below the method used; the price, demand and supply results; and our conclusions. We discuss the results for Ontario and Quebec; the changes for all of Canada are shown in the Appendix tables.

Our starting, or base case of natural gas supply, demand, and prices (and of economic growth, and other energy supplies, demands and prices) was based on the Low Case[3] in *Canadian Energy Supply and Demand*, September, 1988 ("the Supply and Demand Report"). Because this case has low oil prices, as natural gas domestic consumption and exports cause natural gas prices to increase, this provokes a larger difference between gas and oil prices and a larger potential consumer response than would have occurred with a starting scenario featuring higher oil prices. The Low Case also has lower commodity (i.e. net of transportation and distribution) prices for industrial gas purchasers than for residential and commercial natural gas customers (so-called price streaming). Streaming may put most of the pressure of adjustment to higher prices on residential and commercial consumers, because residential and

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1. A possible exception to this proposition is a supply source which requires an export market, failing which the supply source would not be developed, but once developed would provide additional supply to Canadians at a marginal cost which is attractive relative to alternative supplies. Such a supply source may have very high front-end development costs, such that its economic viability depends upon it being able to flow initial volumes of gas exceeding the absorptive capability of the domestic market. For projects of this kind, an Export Impact Assessment using methods illustrated here would require a revision of the supply curve for gas serving the domestic market, to take account of the incremental domestic supply from the time the project would be commissioned, till it would terminate. The later consequences of having used this gas earlier in time than without the export component may happen so much later that domestic users would have ample time to adjust their energy supply portfolios accordingly. In these circumstances, the different timing of resource depletion would be more an issue for cost-benefit evaluation than for market adjustment problems.
2. With the growing integration of natural gas flows between Canada and the U.S., provided that Canadians can freely trade gas with the U.S., the prices of gas in Canada will reflect supply, demand and consequent price conditions in the U.S. market. This does *not* mean that Canadian prices are "made in the U.S.A." and that Canadian supply arrangements can have no impact on Canadian prices. What it *does* mean is that the more gas both Canadians and Americans consume, and the costlier the marginal resources required to satisfy that consumption, the more expensive will natural gas be for Canadian and American consumers. The marginal resource may be Canadian, or American, or both, depending upon the optimal sourcing between particular supply and demand regions. The impacts of both increasing North American demand and Canadian exports on Canadian prices is best estimated using a gas flow modelling framework which integrates supply, demand and transportation characteristics across North America, and which portrays market behaviour on the basis of economic principles which are reasonable given the trade policy environment.
3. The starting scenario is the low case in the report modified by fully iterating it to balance the market to reflect the final export volumes in that report (see table A6-10 and footnote [a] to that table on p. 325).

commercial prices must increase more than proportionately in order to maintain industrial prices at or near parity with heavy oil.[1]

Furthermore we have selected for our impact case a reasonably large export increase. In both the high and low scenarios of the 1988 Report, exports attain and remain at about 1 450 PJ per year, compared with 1987 exports of about 1000 PJ and 1988 exports of about 1 300 PJ. On top of the 1 450 PJ projected in the Supply and Demand Report, we add another 550 PJ, bringing Canadian exports to about 2 000 PJ by 1992 (about twice their 1987 level within five years). The difference this makes to cumulative exports is that between 1988 and 2005, instead of the 26.7 EJ of cumulative exports in the base case, we have 34.4 EJ in the impact case, a difference of 7.7 EJ, which represents about 17% of base case reserves additions over the study period. This would boost Canadian gas exports toward the upper end of the range foreseen by other analysts.

Both the choice of the starting (base) case and the size of additional natural gas exports provide conditions which should make for a good test of the capability of energy market adjustment.

The methodology for balancing natural gas supply, demand and prices is that described in the Supply and Demand Report. We first measure the impact of the increased production needed for additional exports on Canadian gas supply costs. We then project new prices for the period to 2005 based on these costs and re-estimate Canadian gas demand using these prices. We iterate between the supply and demand models until there emerges one price track at which the amounts supplied and demanded are the same. We then compare gas prices, gas demand and competing fuels demands between the base and the impact case.

We do not test whether at these prices the assumed 2 000 PJ/yr export would be fully sellable in the U.S. market; for present purposes we assume it will be. The aim of the exercise is not to assess

Natural Gas Exports Range of Views

	(Bcf) Year 2000
CERI	
High	2 000
Low	640
The WEFA Group	1 900
DRI	1 831
EIA	2 500
GRI	1 600
EM&R	1 500
EMF	
High	2 000
Low	500

Legend:

CERI = Canadian Energy Research Institute, February 1988, Study No. 26, p. 18.

The WEFA Group = Energy, Metals and Minerals, The WEFA Group U.S. Energy Forecast, Summer 1988 p. 7.81.

DRI = Data Resources Energy Review, Summer 1988, Volume 12, Number 2, p. 65.

EIA = Energy Information Administration, Annual Energy Outlook 1987, Table A9.

GRI = Gas Research Institute, 1988 Baseline Projection of U.S. Energy Supply and Demand to 2010.

EM&R = Energy, Mines and Resources Canada.

EMF = North American Natural Gas Markets: EMF 9 Summy Report, Energy Modelling Forum, Stanford University, Stanford, California.

(From *Canadian Energy Supply and Demand*, Sept. 1988, p. 127, inset table).

1. In a case where natural gas prices are streamed, the commodity price to residential and commercial consumers exceeds that to industrial consumers and exceeds the average wellhead price. In a no-streaming case, the commodity price is equal to the wellhead price for all sectors, but since industrial gas demand may be lower (than in a streaming case) transportation and distribution costs are higher to residential and commercial consumers than in the streaming case (the gas market is smaller). Streaming puts the most pressure of adjustment on residential and commercial users only if the difference between the commodity gas price and average wellhead price for these sectors in the streaming case exceeds the difference between the transportation and distribution cost from the streaming to no-streaming case. For example, in the 1988 Supply and Demand Report low case, we found that Ontario residential consumers would pay about 6.5% more with streaming than without it (see "Canadian Energy Supply and Demand 1987-2005", page 32).

whether the high export case is likely, but rather to evaluate the issue of its impact on the Canadian market should it occur.

The gas supply analysis has been conducted using two supply scenarios for the Western Canada Sedimentary Basin.

The Average Resource Case is based on an ultimate technical resource potential of 225 EJ, which corresponds to an economic potential of 205 EJ. This is the GSC's average expectation (i.e. 50% probability estimate) of natural gas potential for the basin derived from a rigorous geological and statistical analysis.

Given the uncertainty regarding the ultimate natural gas potential, a Low Resource Case has also been evaluated. This is based on the GSC' high probability estimate (>95% probability) of 190 EJ technical potential for the WCSB. The corresponding economic potential is 180 EJ.

Supply costs are consistent with those used in the 1988 Supply/Demand Report (low case) and are presented in Figure S-1 for both the Average and Low Resource Cases. These unit costs are used as the basis for the estimation of fieldgate prices. The lower resource potential carries with it an expectation of higher supply costs, while a higher potential would imply lower costs. A high ultimate potential case was not considered because lower gas costs imply less need for adjustment.

The supply analysis also requires that supply costs be provided for frontier natural gas. For the purposes of this analysis, it has been assumed that supply of 0.5 EJ/YR would be available from each of six pipeline projects at supply costs ranging from $2.50/GJ to $4.60/GJ (1987$). The supply costs for the initial project are based on the Esso/Shell/Gulf applications. It should be noted that the supply costs for the remainder of the projects, while thought to be representative of the cost range which would likely be appropriate for frontier supply, are considerably more speculative than those which have been provided for the WCSB and should only be considered to be illustrative

The results for the Low Resources scenario, shown in the lower half of Appendix Tables 1 to 4, are based on a new base case[1] with the same export levels of about 1450 PJ used in the average resource case, but with the low resource supply cost profile (labelled 190 EJ) shown in Figure S-1.

Results - Prices

(1) In the ***average resource scenario*** the price impacts are noticeable. The Ontario residential sector (Figure 1)[2] natural gas price increases between 1987 and 2005 at about 2.7% per year in the high export (impact) case, compared with about 2% per year in the base case. In any year between 1995 and 2005, natural gas ranges from about 9% to 14% more expensive than in the base case for Ontario and Quebec households (Figure 2).

In the ***low resource scenario***, the natural gas price increases at about 2.6% per year in the base case and 3% per year in the high export (impact) case. In any year between 1995 and 2005, natural gas ranges from about 7% to 12% more expensive with high exports than with lower exports. (Figures 3 and 4)

Ontario and Quebec residential consumers in the year 2000 would pay 25% more for their natural gas in a high export/low resource world than they would in a lower export/average resource world. The difference is 23% in 1995.

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1. Comparing the two base cases, shows the impact on prices and demand of lowering the resource estimate, assuming no difference in the level of exports (1450 PJ). For example, in the Ontario residential market, in the year 2000, the burner tip gas price is $7.68 per GJ in the low resource scenario, versus $6.92 per GJ in the average resource scenario, a difference of about 11%. Consequently, gas demand is 267 PJ in the low resource scenario rather than 295 PJ, a difference of 9.5%. The lower resource expectation implies higher costs, higher prices and reduced demand. (It is reasonable to expect that with higher costs of a scarcer resource, export demand would fall below the 1450 PJ feasible with a lower cost resource, mitigating the extent of the domestic price increase and demand decrease. These consequences can be assessed using a general equilibrium modelling framework of the Canadian and U.S. gas markets; we did not do this, hence our present approach slightly exaggerates domestic price impacts in the low resource scenario).
2. Commercial sector price impacts are similar. The industrial sector is of little interest to this analysis, which focuses mainly on substitution between gas, oil and electricity as a result of changing relative prices. The relative price to industry of gas and oil is held at parity by price streaming in both the base and impact cases.

(2) In the ***average resource scenario***, price ratios between gas and competing fuels also increase. Gas prices remain below electricity prices in the high export (impact) case for Ontario (Figure 5) till very near the end of the study period when gas becomes costlier than electricity, but by only 3%. In Quebec, gas prices exceed electricity prices several years earlier than in the base case. (Figure 6)

Gas becomes costlier than light fuel oil some years earlier in both provinces under the high export conditions.

These general observations also apply in the ***low resource scenario***; however, in this case gas becomes even more costly than competing fuels relative to the situation in the average resource scenario, as illustrated by the table below:

Ratio of Gas to Light Fuel Oil Prices in 2000

		Resource Expectation Average	Low
Ontario	(1 450 PJ export)	.90	1.00
	(2 000 PJ export)	.98	1.12
Quebec	(1 450 PJ export)	1.09	1.21
	(2 000 PJ export)	1.19	1.37

(See also Figures 7 and 8)

Results - Demand

(3) In the ***average resource scenario*** for the ***residential sector*** *total residential energy demand* is lower in 2005 by about 2.5% in Ontario (Figure 9) and 0.5% in Quebec (Figure 10) in the high export relative to the base case. The impact is greater in Ontario than in Quebec because natural gas has a larger share of Ontario's residential energy market than of Quebec's.[1] The difference in demand for electricity between the two cases is negligible in both provinces. In both the base and impact cases, demand for light fuel oil (LFO) decreases from 1987 consumption levels; however, the rate of decrease is lower in the high export (impact) case than in the base case. As a result, demand for light fuel oil is greater in the impact case than in the base case, starting from about 20% greater in 1995 and reaching about 50% greater in 2005. However, even by 2005, impact case LFO demand is still below 1987 levels.

In the ***low resource scenario***, total domestic energy demand differs by very little between the two cases by 2005 in both provinces. In both provinces the base and high export (impact) cases both exhibit heavier reliance on LFO than would occur in the average resource scenario. In Ontario, residential LFO demand in 2005 would be close to the 1987 level. In Quebec, LFO demand would be about two-thirds of the 1987 level in the high export (impact) scenario, while it would be a bit less than half the 1987 level in the base case. (Figures 11 and 12).

(4) For the ***commercial sector*** in the ***average resource scenario***, *overall energy demand* is slightly lower in 2005, by only about 2% in Ontario (Figure 13) and 1.4% in Quebec (Figure 14) in the high export (impact) case relative to the base case. (Natural gas has a larger share of Ontario's than of Quebec's commercial sector energy market, hence the impact on total energy demand of an increase in natural gas prices is greater in Ontario than in Quebec.[1]). There is virtually no difference in demand for electricity between the base and impact cases. Natural gas demand is lower in 2005 by about 5.3% and 6.4% in Ontario and Quebec, respectively, in the high export case relative to the base case. Oil product demand falls in both cases between 1987 and 2005, but by much less in the high export case than in the base case. By the year 2005, high export case oil product demand is about 28% and 9% greater than base case demand in Ontario and Quebec respectively.

In the ***low resource scenario***, there is very little change in overall Quebec and Ontario commercial energy demand between the impact and base cases. By 2005 provincial natural gas demand in the high export case is about 4% below base case levels. Ontario oil

1. For a given variation in the price of natural gas in a particular sector and region, a larger share of natural gas leads to a larger impact on the average energy price. Thus the decline in energy demand is greater in Ontario than Quebec.

product demand falls by 10% in the base case between 1987 and 2005, but increases to between 5% and 10% above the 1987 level in the high export (impact) case. In Quebec, oil product demand in 2005 is about 8% below the 1987 level in the base case, but at the 1987 level in the high export case. Between 1995 and 2000, Quebec commercial oil demand is about 4% above the 1987 level in the high export case. (Figures 15 and 16)

5) For Canada as a whole, in the ***average resource scenario*** total end use energy demand, excluding the transportation sector, is lower in 2005 by 0.9% in the impact case relative to the base case (Table 1). Natural gas use is relatively lower by 4.3% and oil use is relatively higher by 4.3%. The required increase in the gas supply is less than the increase of exports because increasing gas prices cause domestic gas demand to fall and demand for oil products to increase. The increase in demand for oil products is less than the decrease in domestic gas demand because higher gas prices cause not only fuel switching, but also conservation.

Total energy demand, again excluding the transportation sector, in Ontario is relatively lower by 0.9%, and in Quebec, by only 0.3%.

In the ***low resource scenario*** the changes in total energy demand are also very small.

Table 1
Summary of Changes [1]
(PJ)

Average Resource Scenario

Domestic Demand	1995 PJ	1995 (%)	2000 PJ	2000 (%)	2005 PJ	2005 (%)
Natural Gas	-69	-3.2	-76	-3.2	-110	-4.3
Oil	26	2.4	35	3.1	50	4.3
Total [2]	-45	-0.7	-39	-0.6	-60	-0.9
Natural Gas Exports	+550	38.0	+550	38.0	+550	38.0
Natural Gas Production*	+501		+494		+459	

Low Resource Scenario

Domestic Demand	1995 PJ	1995 (%)	2000 PJ	2000 (%)	2005 PJ	2005 (%)
Natural Gas	-65	-3.0	-74	-3.2	-77	-3.2
Oil	26	2.3	34	2.8	39	3.2
Total [2]	-39	-0.7	-40	-0.6	-38	-0.5
Natural Gas Exports	+550	38.0	+550	38.0	+550	38.0
Natural Gas Production*	+505		+496		+493	

1. High export (impact) case minus base case. The percentages show corresponding differences as a percent of the base case.
2. Excludes transportation sector.
* Gas production includes shrinkage
Source: Appendix 1, Table 4, Canada, natural gas and oil products

Results - Supply

6) In the control case of the ***average resource scenario*** (225 EJ), productive capacity increases to approximately 4.7 EJ per year by 2005, and remain relatively constant thereafter, to sustain fixed export level of 1.5 EJ per year (Figure S-2). To sustain the impact export level of 2.0 EJ per year, the productive capacity increases to approximately 5.2 EJ per year by 2005 and remain at approximately that level thereafter (Figure S-3).

This projection of productive capacity requirements has implications for both the level of drilling activity in Western Canada and for the pace of frontier development activity.

In the control case, exploratory drilling levels in the WCSB are projected to increase to a sustained level of approximately 4.5 million metres per year (Figure S-4). This is a high level of drilling activity, but is lower than historical peak activity. In the impact case, exploratory drilling levels of 5.5 million metres per year would be required by the late 1990s, with modest increases thereafter. This level of exploratory drilling, which would be required on a sustained basis, is higher than the peak exploratory drilling level of 5.3 million metres per year which occurred in 1980.

At sustained export levels of 1.5 EJ per year, frontier supplies from the Mackenzie/Beaufort region become economic in 2001. Beyond that point there is an increasing reliance on frontier supplies, to the extent that four or five major frontier projects would be required by

the end of the projection period. In the impact case, frontier supplies become economic in 1999 and all of the speculative projects would need to be developed by the end of the period to provide sufficient supply to meet the projected demand levels.

7) In the base case of the ***low resource scenario*** (190 EJ), productive capacity increases to approximately 4.7 EJ per year by 2005 and remains relatively constant thereafter to sustain the export level of 1.5 EJ per year (Figure S-5). To sustain the impact case export level of 2.0 EJ per year, the productive capacity increases to a level of approximately 5.2 EJ per year by 2005 and remains at that level on a sustained basis (Figure S-6).

   Exploratory drilling levels in the WCSB are projected to increase to 5.5 million metres per year in the base case. In the impact case, exploratory drilling levels increase to about 6.5 million metres per year. In both cases, sustained levels of activity are significantly higher than they have been historically in the WCSB and exceed the peak levels achieved in 1980.

   In order to meet the projected productive capacity requirements, an aggressive program of frontier development is required in both cases. In the base case, two frontier projects would have to be completed by 2005 and all of the speculative projects would be onstream by 2016. In the impact case, start-up of the first frontier project would be in 1996, with three projects onstream by 2005 and all of the projects onstream by the end of the projection period.

Conclusions

The results of our analysis suggest several tentative conclusions.

If Canadian natural gas resources are found in concert with the GSC average resource expectation, a large, sustained increase in gas exports may cause some domestic gas price increases, but is not expected to lead to major consumer adjustment difficulties. Residential and commercial natural gas prices should rise by about 15 percent by 2005 on account of the higher exports, resulting in a reduction of total energy demand (exclusive of transportation) of less than 1 percent and a substitution of some natural gas use by oil products. The relative increase in oil product demand is only up to some 4 percent and results in less decrease over time in oil product demand than is otherwise expected to occur.

Consumers have little incentive to change consumption patterns abruptly because of small differences in the rate of fuel price change, or to accelerate switching between fuels unless gas becomes considerably more expensive than competing fuels. Consumer response to the price change is expected to be gradual and lagged, because the incentive to switch fuels requires a sustained price advantage sufficient to compensate for an earlier timing of equipment change than would occur in the base case.

Of course, the extent of the gas supply cost increase, and the extent of consumer reaction to increased gas prices depends largely upon our estimates of the responsiveness of supply and demand to price. Different estimates of this responsiveness would produce different impacts.

The preceeding analysis suggests that the supply side should be the primary focus of attention when considering adjustment difficulties.

In all cases which were examined, there is an increasingly heavy reliance on frontier supplies to maintain productive capacity in the period beyond 2000. The extent to which this dependency exists is related primarily to the ultimate resource potential estimated for the WCSB.

Ultimate potential estimates used in this analysis are based largely on existing GSC work and range from 190 EJ (high probability estimate) to 225 EJ (average expectation estimate). This is the range of estimates used in the 1988 Supply/Demand Report, with the base case being the 225 EJ case. The GSC is currently reviewing their natural gas potential estimates, which may lead to an upward revision. However, at this time we consider this to be an appropriate range for use in the examination of the potential for adjustment problems to occur as a result of increased export levels.

Considerations in establishing whether adjustment problems will occur with respect to supply availability from the WCSB include the following:

- the quality and distribution of remaining ultimate potential,

- the capability of the industry, both in terms of physical equipment and skilled personnel, to initiate and maintain the levels of exploratory drilling activity required to sustain productive capacity, and
- lead times for development, particularly in environmentally sensitive areas.

In both the average and low resource scenarios, substantial frontier development activity must occur in the period beyond 2000 in order to provide sufficient productive capacity, particularly in the high export case. The analysis therefore suggests that the pace of frontier development will be a key determinant in assessing whether adjustment problems will occur. Considerations in this regard include the following:

- distribution of reserves, both in terms of geographical area and pool size,
- development costs, which to a large extent will be affected by technological advances over this period, and
- environmental issues - much of the remaining potential is in the more remote offshore areas and the Arctic Islands.

There is a high degree of uncertainty associated with many of these issues and therefore some doubt as to whether the level of development suggested by this analysis can reasonably be expected to occur in the timeframe required.

Particularly because of the above-mentioned uncertainties about the viability of the supply arrangements needed to support these levels of consumption, it could be that this analysis understates potential adjustment requirements.

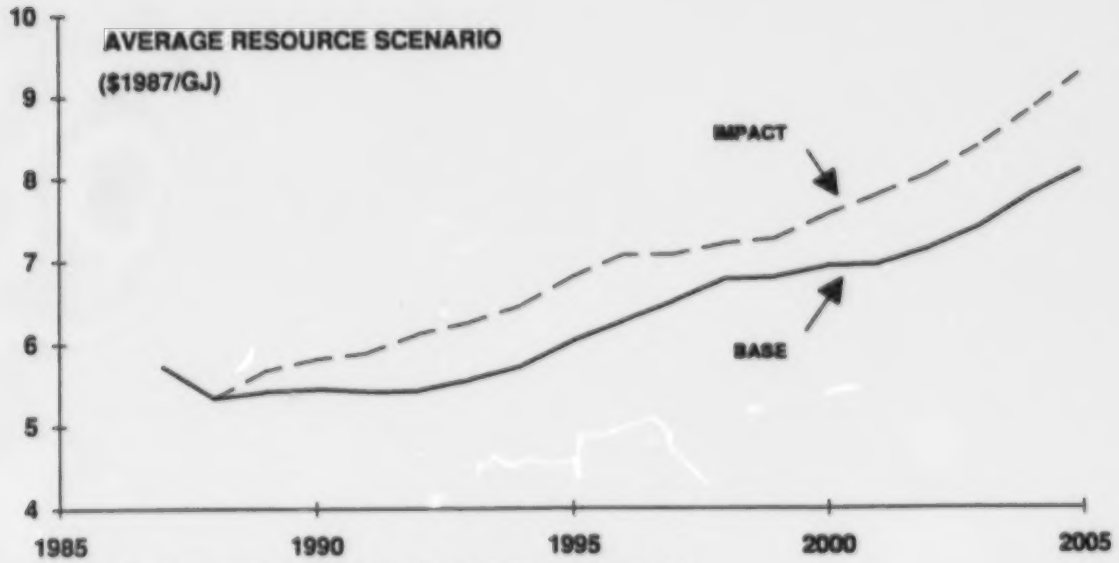
For example, if it were simply not possible to sustain these levels of supply at the time they would be needed, the supply curves underlying gas price formation would be steeper - meaning less quantity available at higher prices, which in turn would imply more demand-side adjustment that portrayed in this analysis.

Therefore, while the paper indicates perhaps a greater level of concern about supply-side rather than demand-side adjustment difficulties, both are related; hence we eschew firm conclusions about whether exports in the range of 2 EJ/year could be sustained without causing some concerns about the adequacy of adjustment processes.

While we can produce quantitative estimates of the size of price, supply, and demand impacts for every year of the projection, it requires additional qualitative information and judgement to measure the ease or difficulty which may be associated with these adjustments. In general, the ease or difficulty of adjusting depends upon the size and abruptness of the required adjustment, and the kind of energy involved.

Figure 1

RESIDENTIAL SECTOR NATURAL GAS PRICE - ONTARIO



Source: The source data for all graphs in this section is in Appendix 1.

Figure 2

RESIDENTIAL SECTOR NATURAL GAS PRICE - QUEBEC

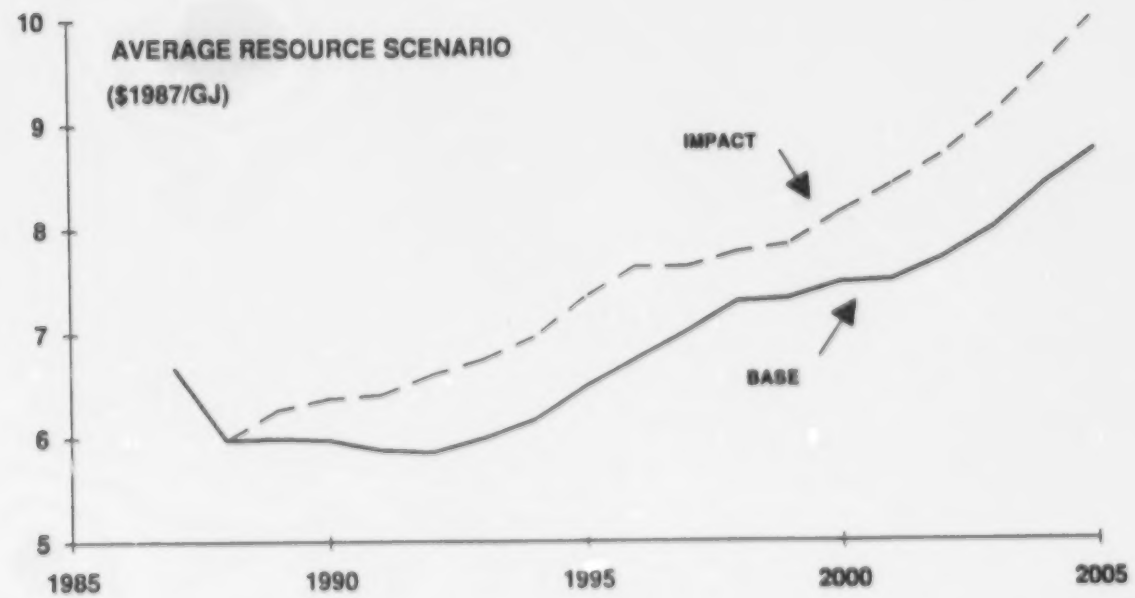


Figure 3

RESIDENTIAL SECTOR NATURAL GAS PRICE - ONTARIO

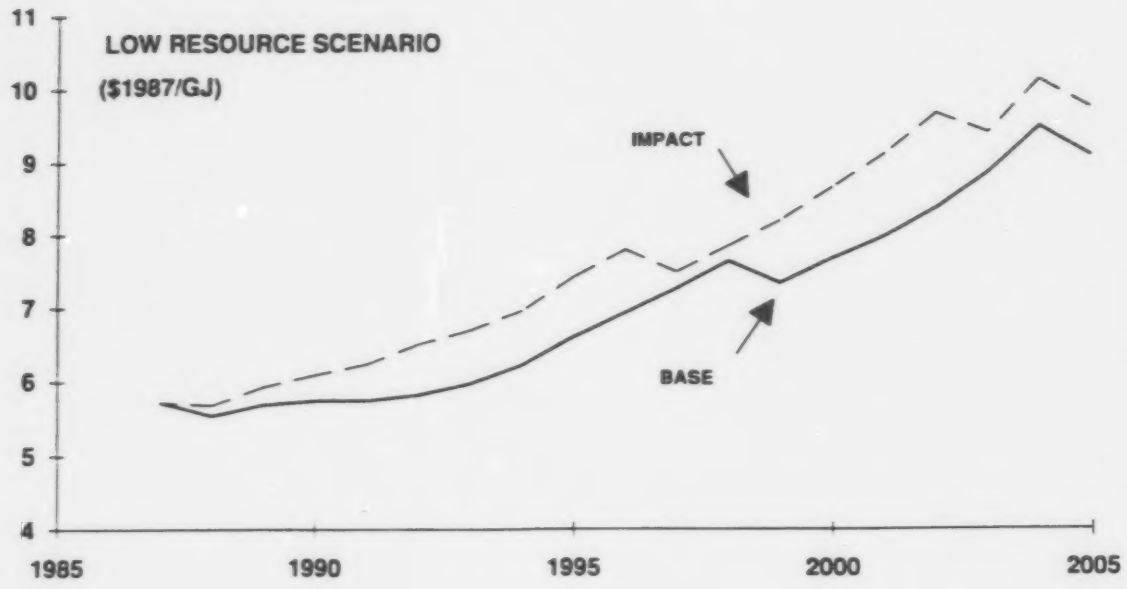


Figure 4

RESIDENTIAL SECTOR NATURAL GAS PRICE - QUEBEC

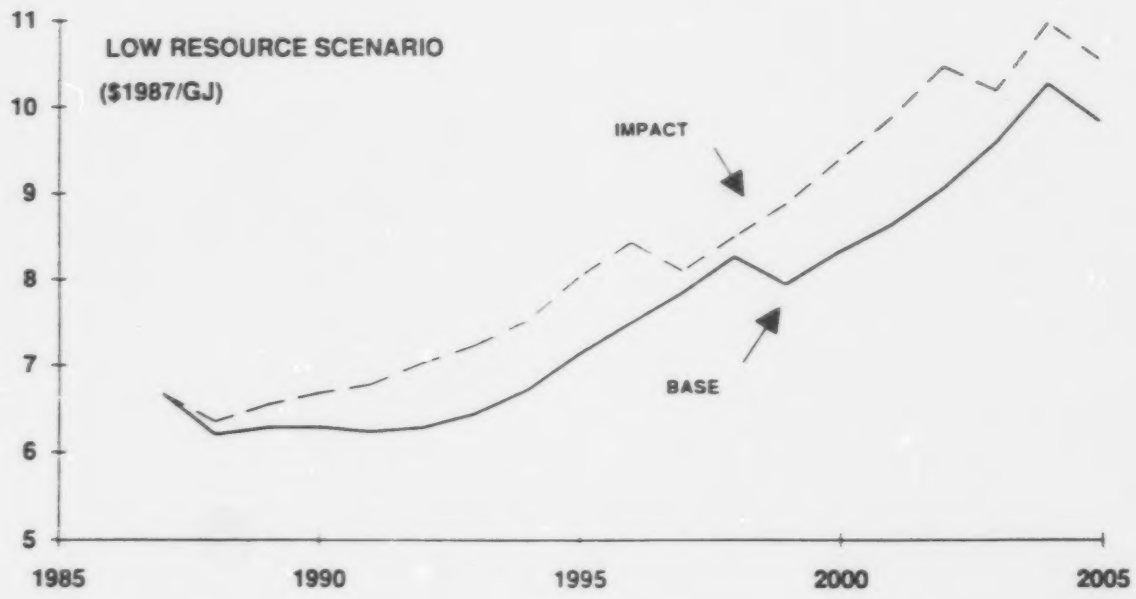


Figure 5
RELATIVE PRICE RATIOS - ONTARIO
RESIDENTIAL

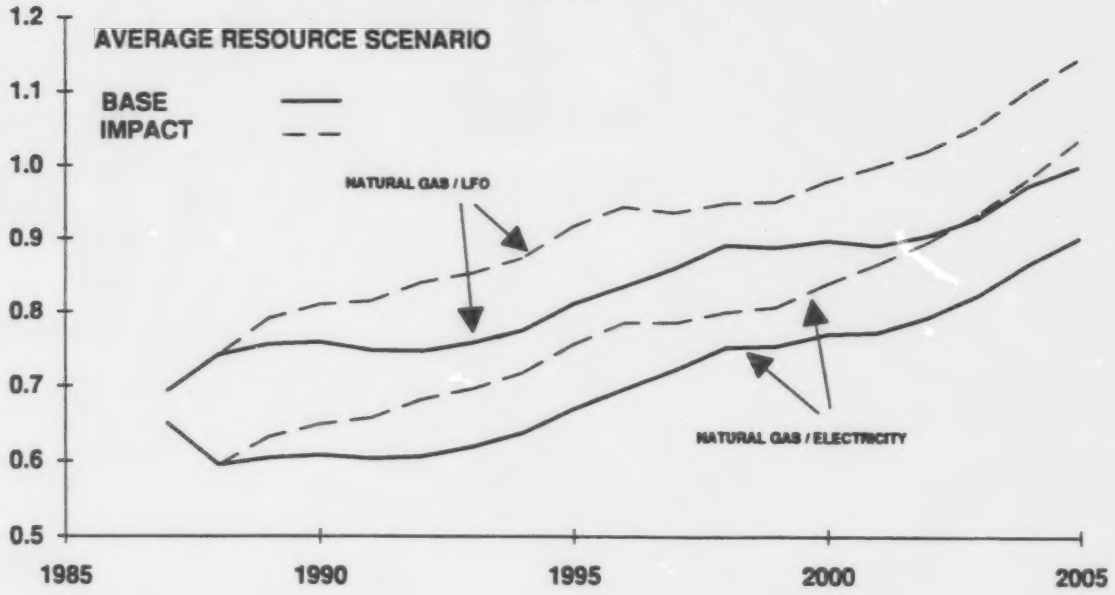


Figure 6
RELATIVE PRICE RATIOS - QUEBEC
RESIDENTIAL

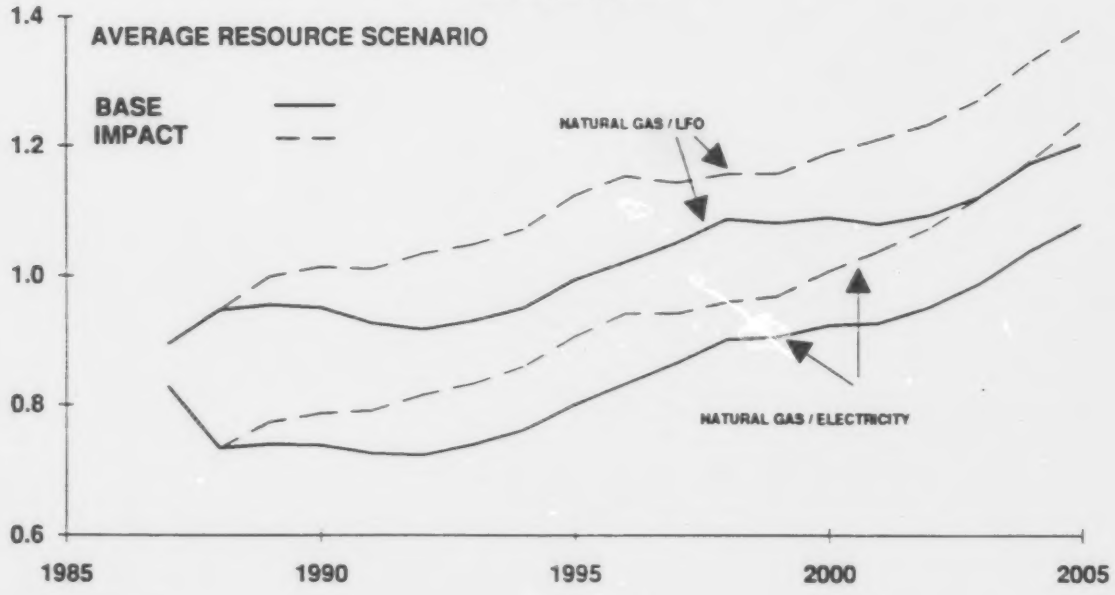


Figure 7
RELATIVE PRICE RATIOS - ONTARIO
RESIDENTIAL

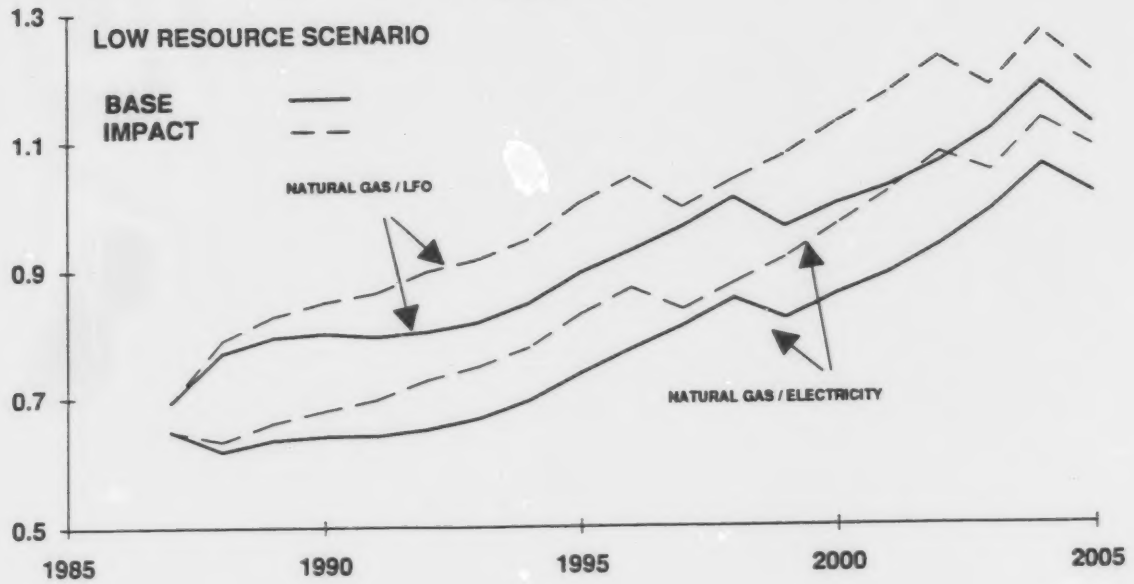


Figure 8
RELATIVE PRICE RATIOS - QUEBEC
RESIDENTIAL

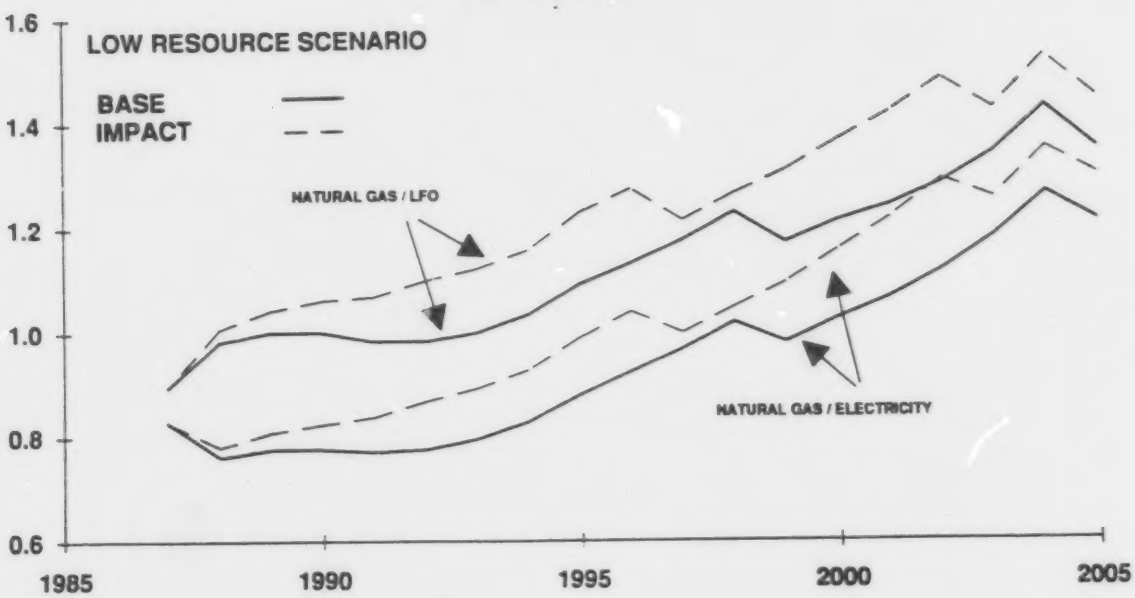


Figure 9
RESIDENTIAL ENERGY DEMAND - ONTARIO
PETAJOULES

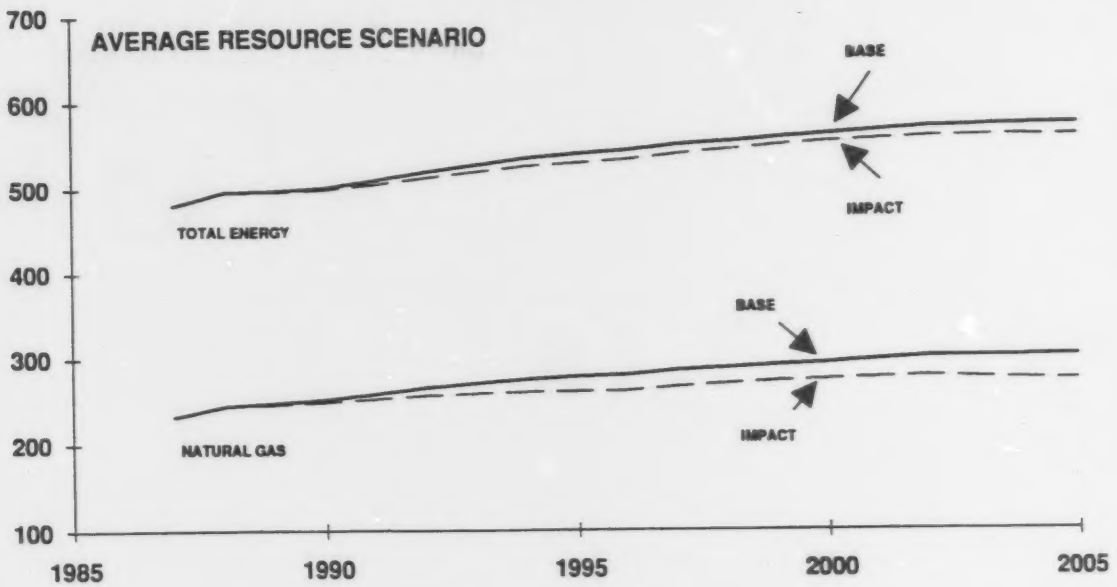


Figure 10
RESIDENTIAL ENERGY DEMAND - QUEBEC
PETAJOULES

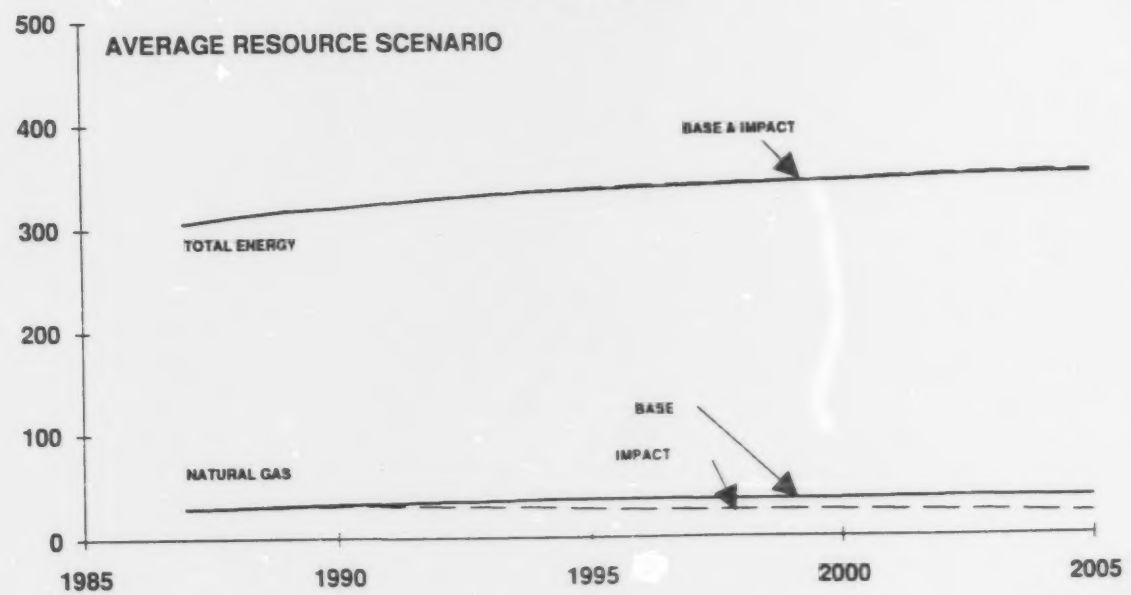


Figure 11
RESIDENTIAL ENERGY DEMAND - ONTARIO
PETAJOULES

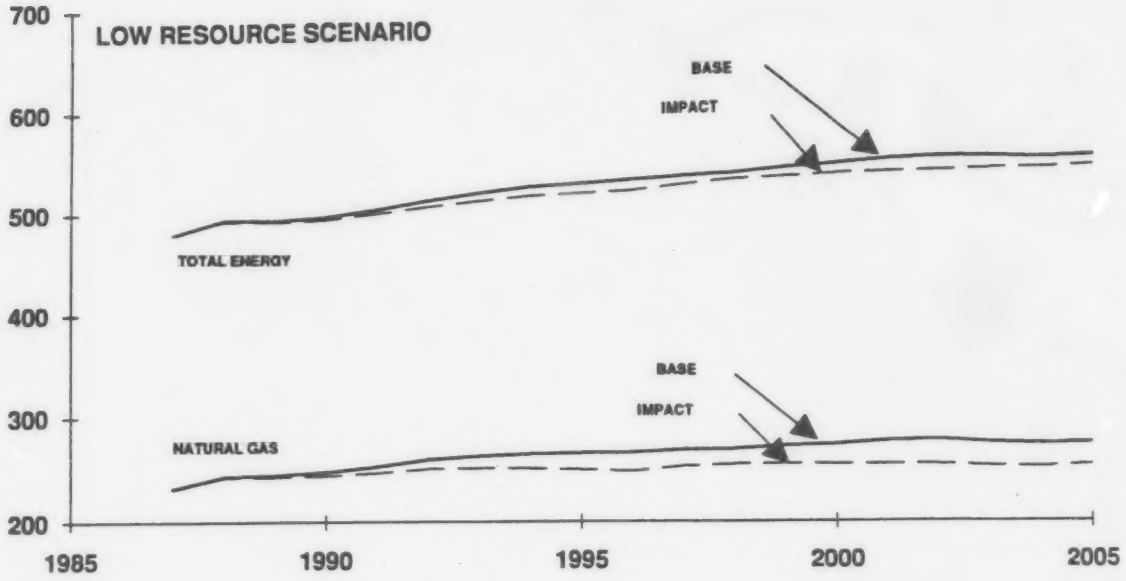


Figure 12
RESIDENTIAL ENERGY DEMAND - QUEBEC
PETAJOULES

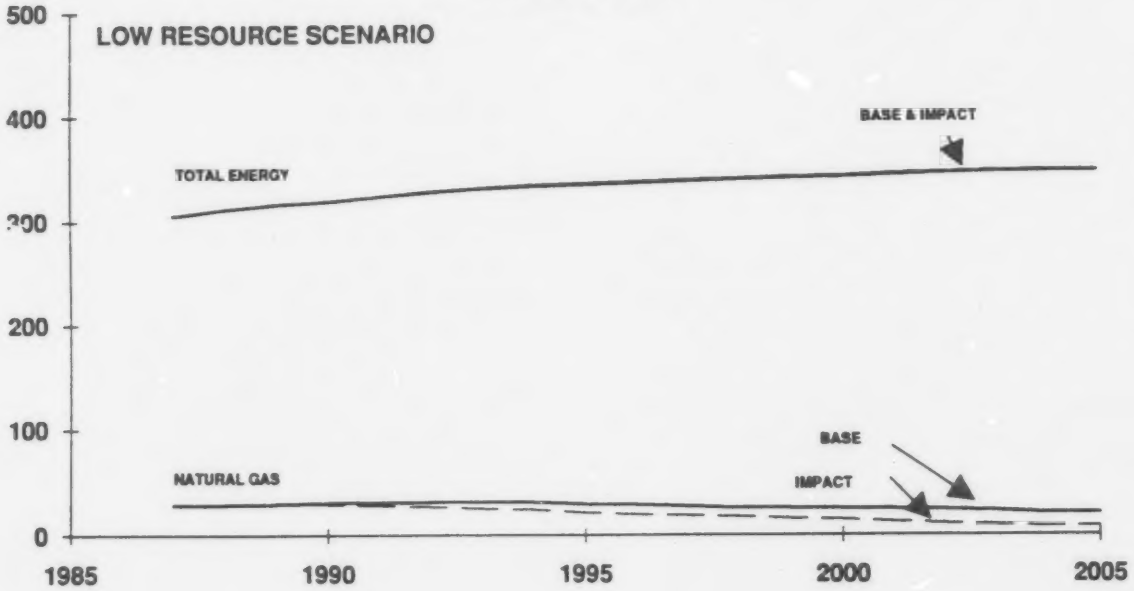


Figure 13
COMMERCIAL ENERGY DEMAND - ONTARIO
PETAJOULES

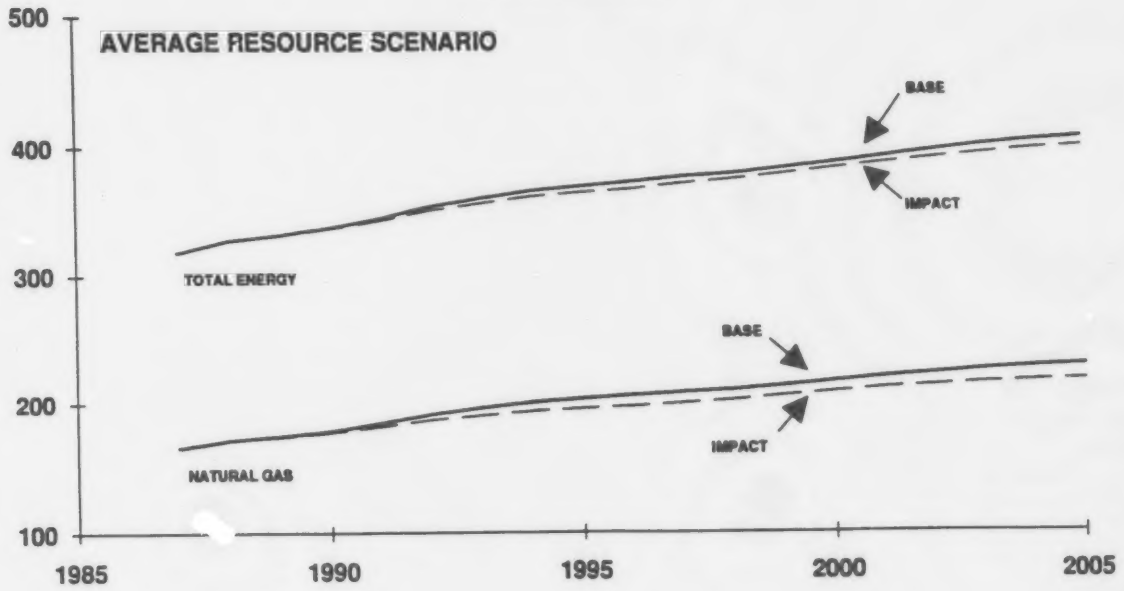


Figure 14
COMMERCIAL ENERGY DEMAND - QUEBEC
PETAJOULES

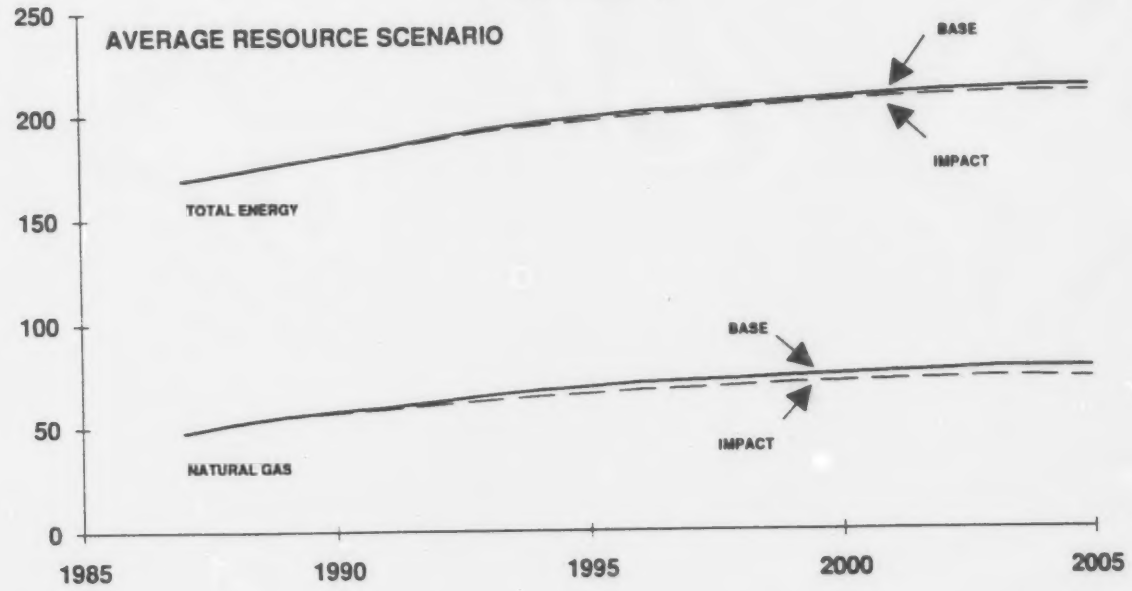


Figure 15
COMMERCIAL ENERGY DEMAND - ONTARIO
PETAJOULES

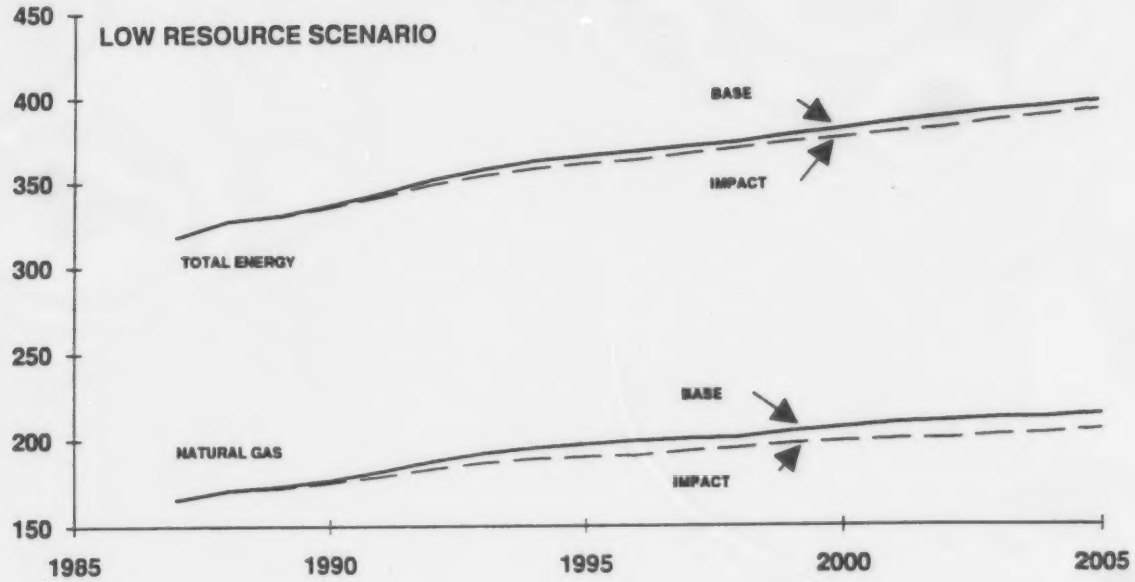


Figure 16
COMMERCIAL ENERGY DEMAND - QUEBEC
PETAJOULES

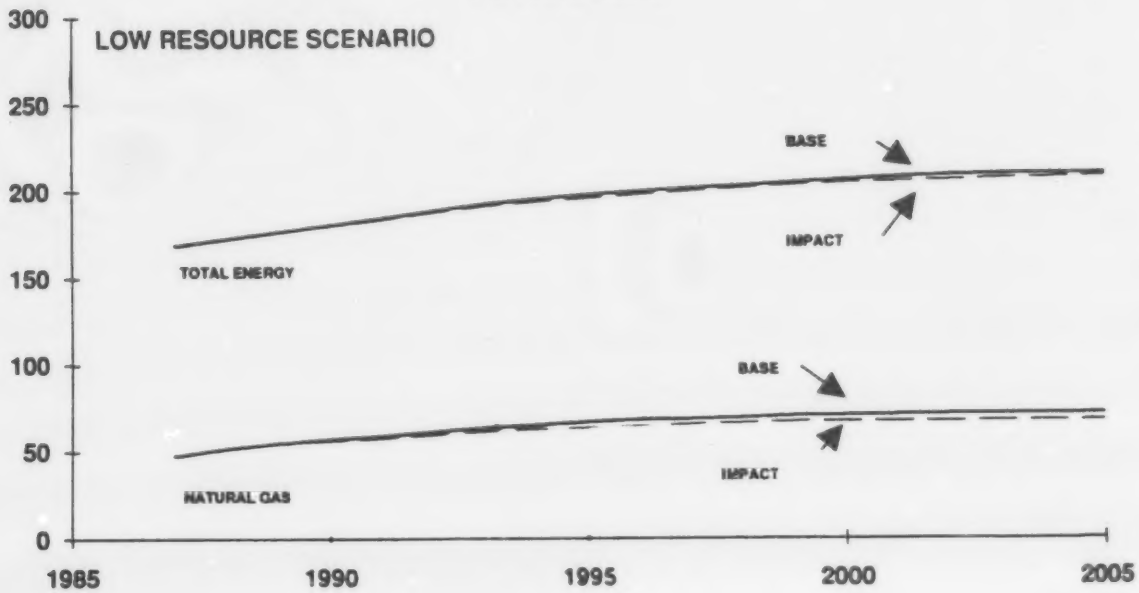


Figure S-1

Net Incremental Direct Costs Western Canada Sedimentary Basin

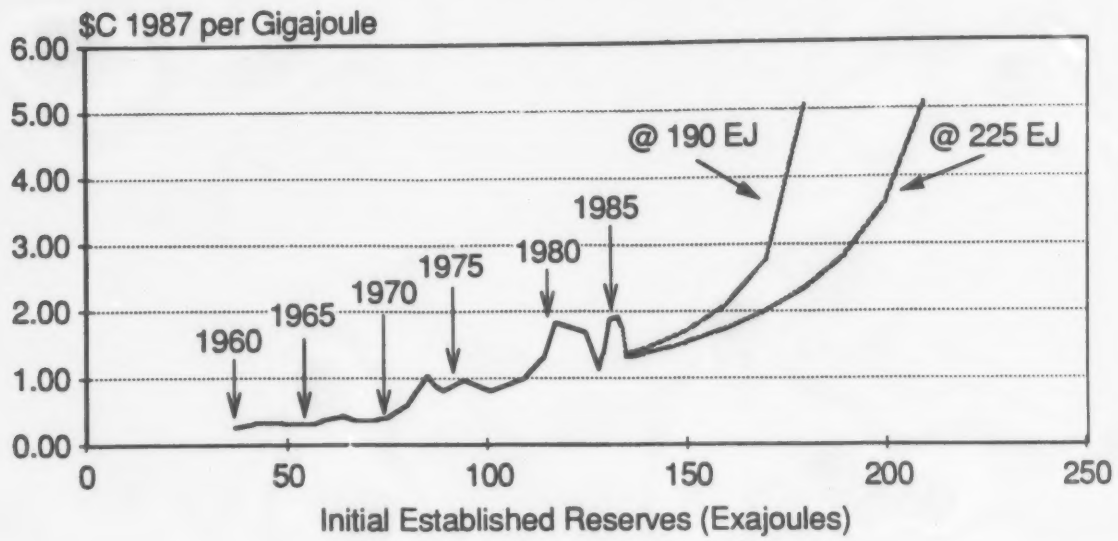


Figure S-2

Natural Gas Supply and Demand For Canada Average Expectation (225 EJ) For WCSB Resources With Exports Of 1.5 EJ Per Year

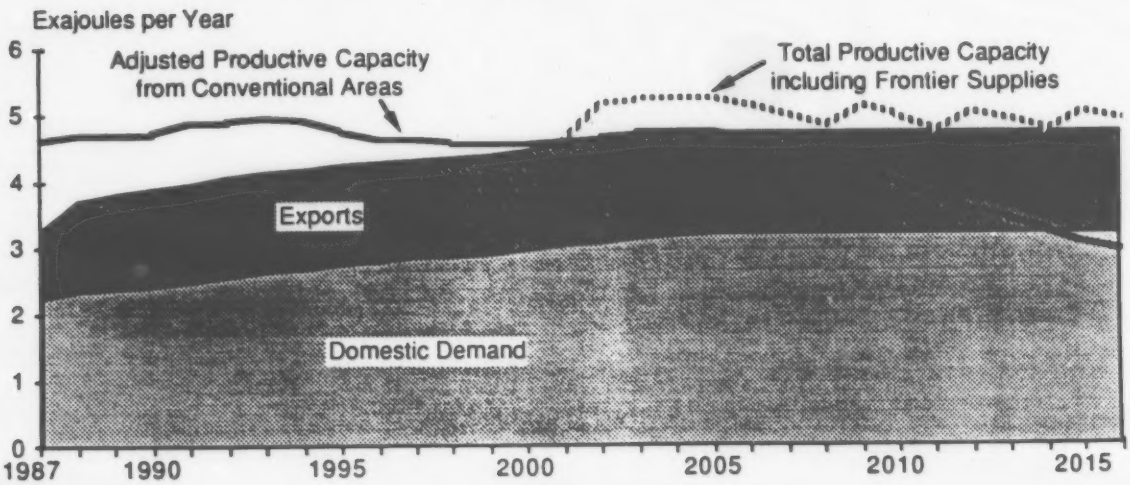


Figure S-3

Natural Gas Supply and Demand For Canada Average Expectation (225 EJ) For WCSB Resources With Exports Of 2.0 EJ Per Year

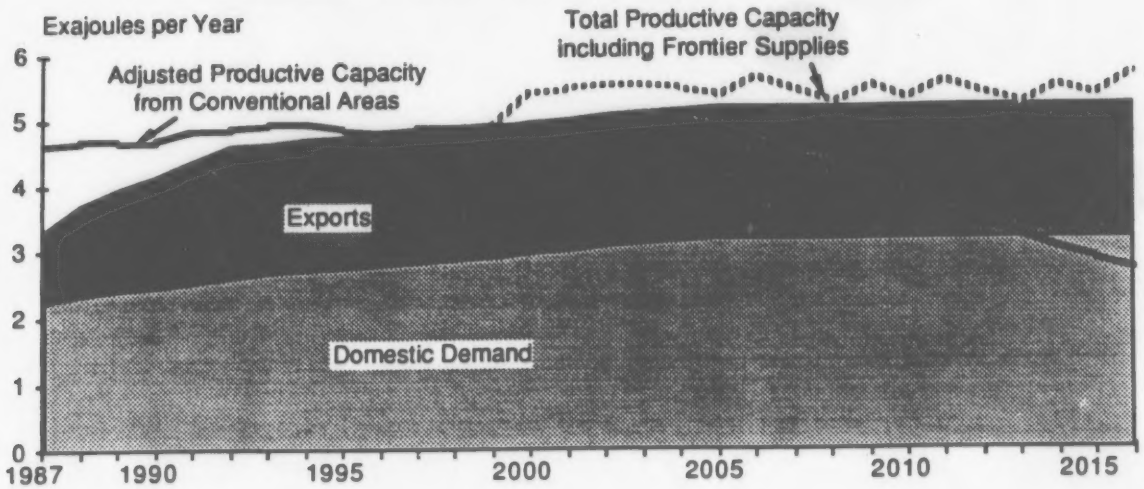


Figure S-4

Total Exploratory Drilling In WCSB Average Expectation (225 EJ) For WCSB Resources

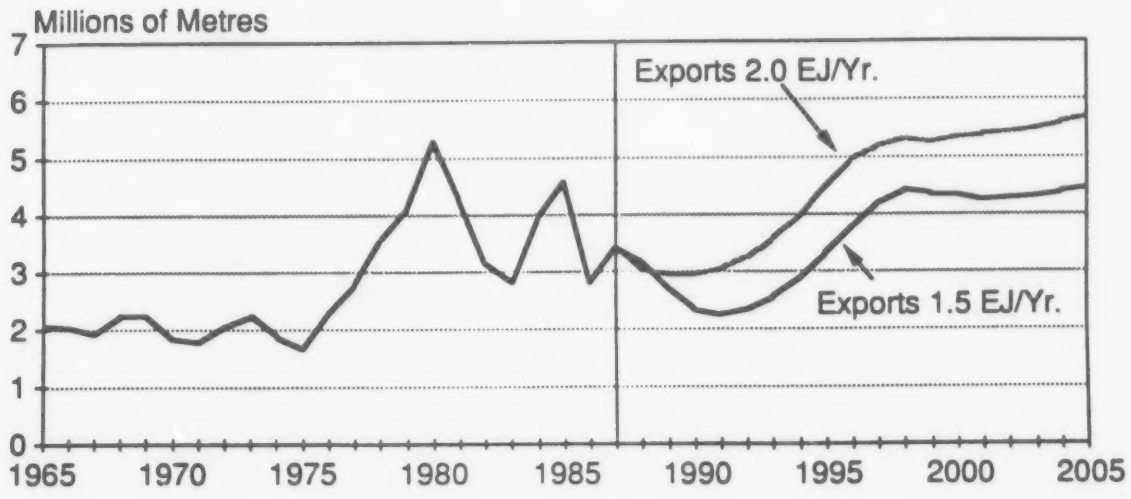


Figure S-5

Natural Gas Supply and Demand For Canada Low Resources (190 EJ) For The WCSB With Exports Of 1.5 EJ Per Year

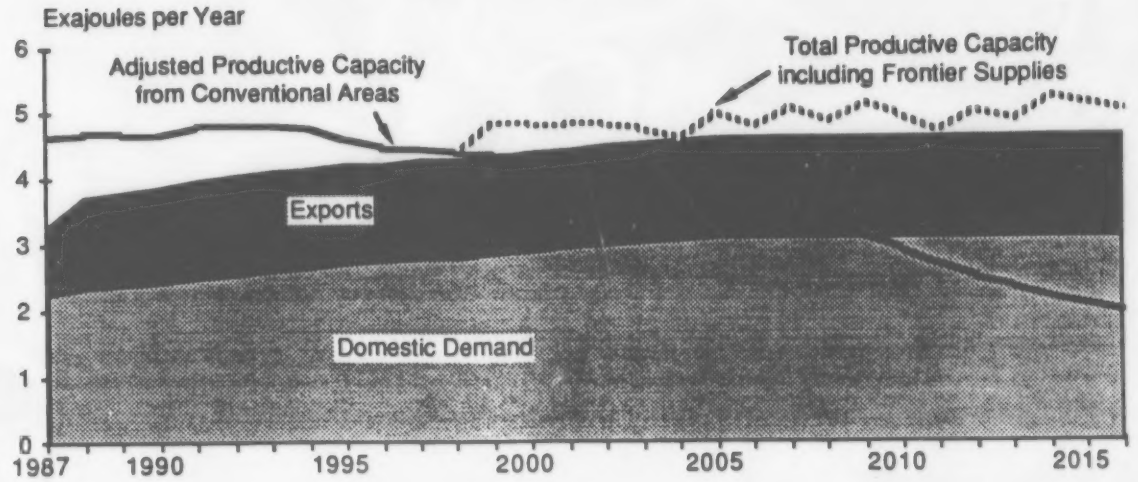


Figure S-6

Natural Gas Supply and Demand For Canada Low Resources (190 EJ) For The WCSB With Exports Of 2.0 EJ Per Year

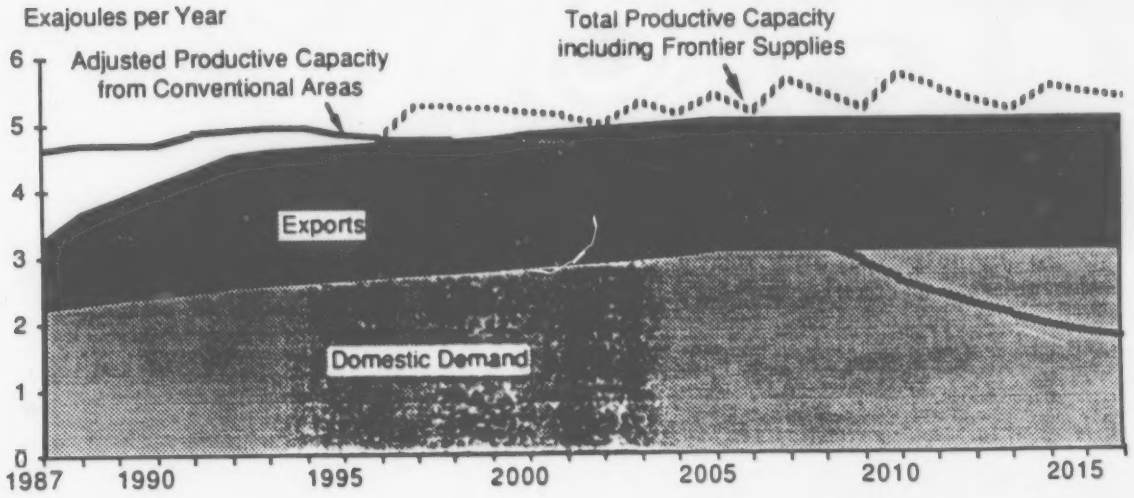
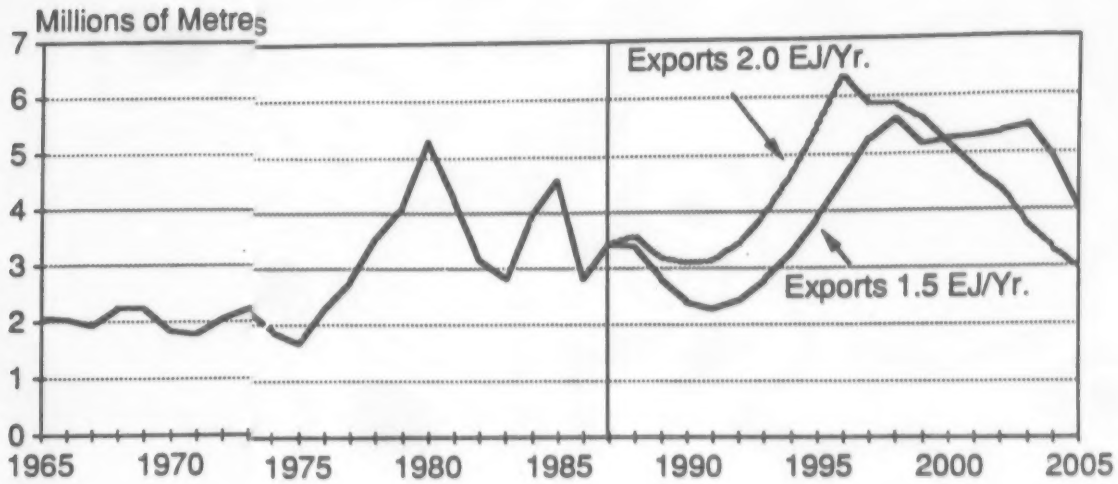


Figure S-7

Total Exploratory Drilling In WCSB
Low Resources (190 EJ) For The WCSB



Appendix 1 - Export Impact Assessment Illustrative Analysis

Table 1
Price Impacts

Average Resource Case

		1987	1995	2000	2005
Ontario Residential					
Natural Gas ($1987/GJ)	B	5.72	6.01	6.92	8.09
	I	5.72	6.79	7.53	9.26
Gas/Electricity (ratio)	B	0.65	0.67	0.77	0.90
	I	0.65	0.76	0.84	1.03
Gas/LFO (ratio)	B	0.69	0.81	0.90	1.00
	I	0.69	0.92	0.98	1.14
Quebec Residential					
Natural Gas ($1987/GJ)	B	6.67	6.49	7.47	8.75
	I	6.67	7.34	8.15	10.03
Gas/Electricity (ratio)	B	0.83	0.80	0.92	1.08
	I	0.83	0.91	1.00	1.24
Gas/LFO (ratio)	B	0.90	0.99	1.09	1.20
	I	0.90	1.12	1.19	1.38
Low Resource Case					
Ontario Residential					
Natural Gas ($1987/GJ)	B	5.72	6.60	7.68	9.06
	I	5.72	7.41	8.65	9.71
Gas/Electricity (ratio)	B	0.65	0.74	0.86	1.01
	I	0.65	0.83	0.96	1.08
Gas/LFO (ratio)	B	0.69	0.89	1.00	1.12
	I	0.69	1.00	1.12	1.20
Quebec Residential					
Natural Gas ($1987/GJ)	B	6.67	7.13	8.30	9.81
	I	6.67	8.01	9.36	10.52
Gas/Electricity (ratio)	B	0.83	0.88	1.03	1.21
	I	0.83	0.99	1.16	1.30
Gas/LFO (ratio)	B	0.90	1.09	1.21	1.35
	I	0.90	1.23	1.37	1.45

B = Base case exports (1450 PJ)
I = Impact or high export case (2000 PJ)

Table 2
Energy Demand (Selected Fuels) PJ/ year

Average Resource Case

		1987	1995	2000	2005
Ontario Residential					
Natural Gas	B	233	279	295	302
	I	233	262	276	274
Electricity	B	145	170	170	176
	I	145	168	170	175
LFO	B	57	39	36	31
	I	57	47	47	46
Total Demand	B	481	539	560	568
	I	481	530	551	554
Quebec Residential					
Natural Gas	B	29	37	37	37
	I	29	28	26	21
Electricity	B	161	203	219	231
	I	161	204	220	233
LFO	B	65	39	29	22
	I	65	46	37	33
Total Demand	B	305	337	345	351
	I	305	336	343	349
Low Resource Case					
Ontario Residential					
Natural Gas	B	233	267	275	276
	I	233	251	256	255
Electricity	B	145	169	172	175
	I	145	168	171	175
LFO	B	57	45	44	42
	I	57	53	55	55
Total Demand	B	481	532	548	551
	I	481	522	538	542
Quebec Residential					
Natural Gas	B	29	30	26	21
	I	29	22	15	9
Electricity	B	161	204	220	235
	I	161	204	221	236
LFO	B	65	44	37	30
	I	65	50	45	40
Total Demand	B	305	336	343	348
	I	305	335	342	347

Table 3
Energy Demand (Selected Fuels) PJ/ year

Average Resource Case

		1987	1995	2000	2005
Ontario Commercial					
Natural Gas	B	166	203	215	228
	I	166	195	208	216
Electricity	B	129	145	150	130
	I	129	145	151	160
Oil Products	B	20	16	16	14
	I	20	19	19	18
Total* Demand	B	318	369	386	406
	I	318	364	382	398
Quebec Commercial					
Natural Gas	B	48	69	75	77
	I	48	66	71	72
Electricity	B	92	100	105	109
	I	92	101	105	109
Oil Products	B	26	25	24	22
	I	26	26	25	24
Total* Demand	B	169	199	208	213
	I	169	197	206	210

Low Resource Case

Ontario Commercial					
Natural Gas	B	166	197	207	214
	I	166	190	199	205
Electricity	B	129	145	151	160
	I	129	145	151	160
Oil Products	B	20	18	19	18
	I	20	21	22	21
Total* Demand	B	318	365	381	396
	I	318	360	376	391
Quebec Commercial					
Natural Gas	B	48	67	71	71
	I	48	64	67	68
Electricity	B	92	101	106	109
	I	92	101	106	110
Oil Products	B	26	26	25	24
	I	26	27	27	26
Total* Demand	B	169	197	206	209
	I	169	196	204	207

* includes energy forms not tabled here

Table 4
Total End-Use* Energy Demand (Selected Fuels) PJ/ year

Average Resource Case

		1987	1995	2000	2005
Ontario					
	B	1870	2193	2346	2480
	I	1870	2178	2332	2459
% Change		0	-0.7	-0.6	-0.9
Quebec					
	B	1130	1298	1363	1411
	I	1130	1294	1360	1407
% Change		0	-0.3	-0.2	-0.3
Canada					
	B	5321	6120	6525	6913
	I	5321	6075	6486	6852
% Change		0	-0.7	-0.6	-0.9
of which					
Natural Gas	B	1822	2199	2385	2563
	I	1822	2129	2309	2453
% Change		0	-3.2	-3.2	-4.3
Oil Products	B	1082	1110	1144	1157
	I	1082	1137	1179	1207
% Change		0	2.4	3.1	4.3

Low Resource Case

Ontario					
	B	1870	2183	2329	2454
	I	1870	2168	2314	2440
% Change		0	-0.7	-0.6	-0.6
Quebec					
	B	1130	1295	1359	1405
	I	1130	1292	1356	1402
% Change		0	-0.3	-0.2	-0.2
Canada					
	B	5321	6089	6478	6838
	I	5321	6046	6436	6800
% Change		0	-0.7	-0.6	-0.5
of which					
Natural Gas	B	1822	2151	2310	2452
	I	1822	2086	2236	2375
% Change		0	-3.0	-3.2	-3.2
Oil Products	B	1082	1127	1170	1195
	I	1082	1153	1204	1234
% Change		0	2.3	2.8	3.2

* excludes the transportation sector

Appendix B

Source: Canadian Energy Supply and Demand 1990-2010, NEB, 1991: Chapter 6.

Chapter 6

Natural Gas

In this Chapter we first discuss our approach to natural gas price formation and flows. Next, our main input assumptions are set out. These relate to natural gas resources and supply costs in each of Canada and the U.S., the pipeline network and tolls, distribution margins, and U.S. and Canadian demand. We then discuss the results for the Control Case, including fieldgate prices, U.S. supply and demand, Canadian exports and imports, domestic demand and the various components of domestic natural gas supply. Finally, we outline the results of sensitivity tests conducted for oil prices, Canadian gas resources, North American gas resources and backstop costs.

6.1 Approach to Price Formation and Gas Flows

We develop our projections of natural gas prices on the premise that Canada participates in an open, integrated and competitive North American natural gas market, in which North American supply and demand conditions determine the prices of natural gas in Canada and in the U.S. Comparative delivered costs from different sources determine the flows from particular sources to destinations. A part of this flow pattern is the trade in natural gas across the Canada-U.S. boundary, comprising mainly but not exclusively Canada's natural gas exports to the U.S. The interregional distribution of these flows indicates the pipeline capacity which may be required over the longer term.

Figure 6-1 shows the basic logic of price determination and flow patterns, and it identifies the relevant factors which we discuss in this chapter.

On the supply side, a number of key assumptions determine the incremental unit cost of natural gas. Incremental costs depend upon the costs of factor inputs (e.g. labour and equipment for exploration, development and processing), and on the finding rate[1], which is in turn related to ultimate potential. In our work, we assume a range of ultimate potential estimates; for each one of them, we assume that as the resource is progressively depleted the finding rate declines, which causes supply costs to increase. This progression of declining finding rates and increasing cost is mitigated, but not eliminated, by ongoing technological progress which we account for in our supply cost estimates. The biggest component of exploration and development costs is the cost of drilling. The main financial variables are interest rates on debt, return on equity, and the debt:equity ratio. The reserves to production ratio influences the level of production costs: the higher it is, the more gas it is necessary to find per unit of production, and the higher the cost attributable to that production.

On the demand side, the market for gas depends mainly upon economic activity, demographic factors (e.g. household formation), fuel preferences (e.g. environmental fuel preference for electricity generation) and the prices of competing fuels (e.g. oil).[2] As the resource base is progressively depleted at a rate determined by cumulative consumption, the gas supply cost increases, which means that gas will be produced only if wellhead prices increase to accommodate these increasing costs.

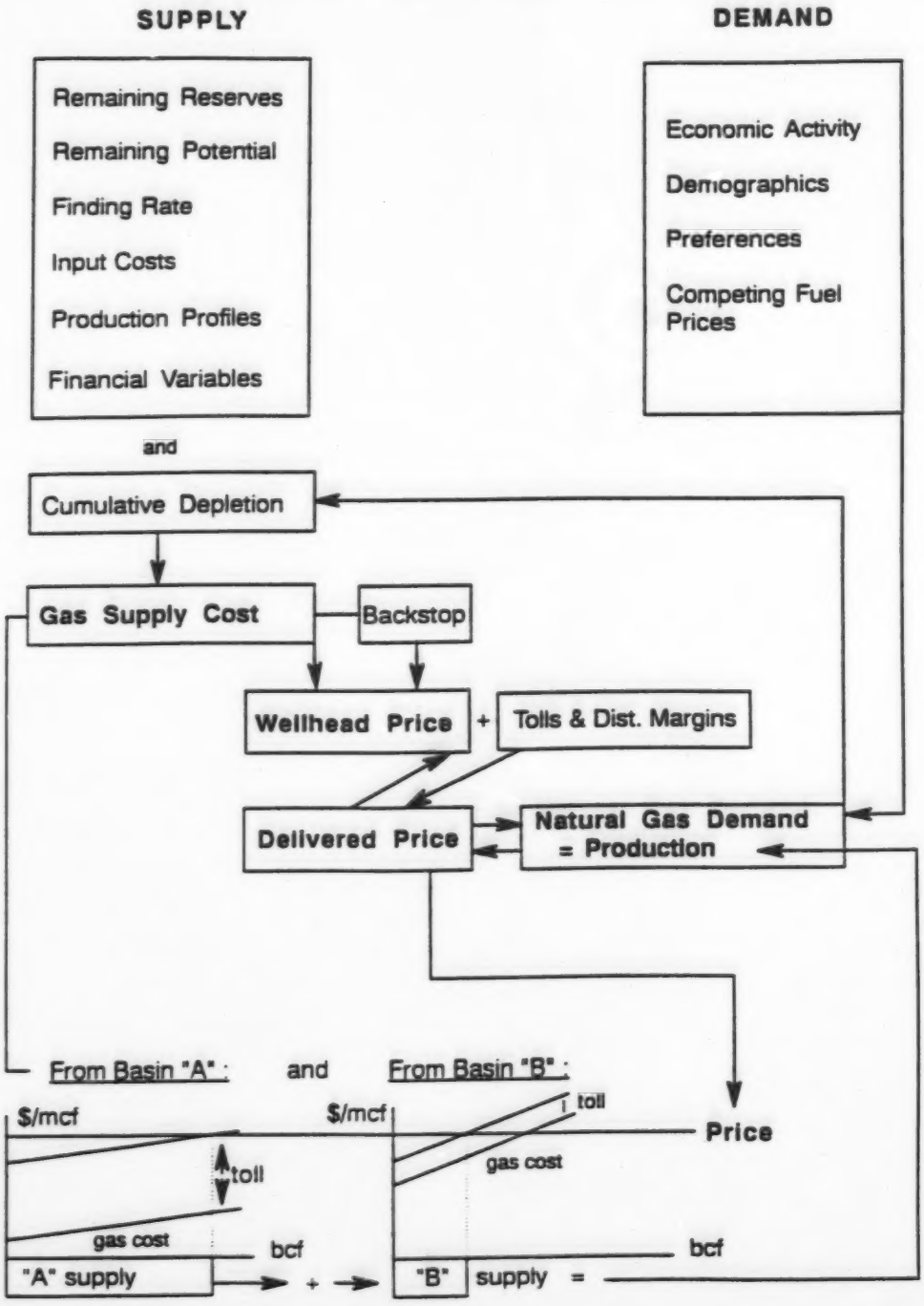
One key objective of our analysis is to find paths of natural gas prices over time, which will balance supply and demand given assumptions about the more important underlying supply and demand conditions. The value of natural gas is different for different users, depending partly on the cost of their alternative fuel options, which differ between users. Because of this, all else equal, aggregate volumes consumed will increase as natural gas prices decrease and vice versa. In principle, there is an amount that would be consumed at a price which is just high enough to elicit the corresponding amount of production. This price is generally

1 The finding rate is the amount of gas discovered per metre of drilling.

2 For Canada, we discussed these factors in previous chapters. We also require demand assumptions for the U.S. market, and we discuss those in this chapter.

Figure 6-1

North American Natural Gas Market Analysis



Relative gas costs between basins and tolls from those basins to a market determine the share of each basin to that market and pipeline flow pattern .

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called the "equilibrium price" because it is at a level which causes quantities produced and consumed to be the same. This equilibrium price is found by an iterative process which successively finds prices that narrow the difference between volumes demanded and supplied, until the market settles on a price at which the demand and supply volumes are about the same. The equilibrium price which the end user pays differs from that which the producer receives because of transportation and distribution costs incurred in moving the gas from the wellhead to the end user.

There is a special feature of the natural gas industry which plays some role in gas price formation: most analysts believe that conventional natural gas is a depletable resource, the cost of which will increase with cumulative consumption, up to a price level at which gas from another source or some other close substitute can be made available in very large amounts relative to consumption. This fuel is called the "backstop resource". The value of the backstop resource influences wellhead prices over all time periods in the projection, to the extent that resource owners know and take future value into account in today's pricing and output decisions.

They do this by adjusting the amount they will supply to the market such that there will be just enough revenue between the market price and the direct supply cost to compensate them in present value terms for making the gas available now rather than holding it in the ground till it gains more value later on. This surplus is commonly known as a "depletion premium" or a "user cost". We use the latter term. The cost of the backstop, the time to exhaustion, the discount rate used for bringing future value to present value and the size of the market are the key factors determining the user cost. This approach to price formation requires that resource owners in aggregate know these values far into the future (notwithstanding that different analysts' estimates of ultimate potential and backstop values differ substantially). The user cost, combined with direct production costs (the level of which at any time results from cumulative consumption up to that time) determines the market price. (We provide a more detailed discussion of the relationship between user cost and price formation in Annex 1).

If royalties were set on the basis of the foregoing principles, the royalty would be the user cost, appropriated by the resource owner (in Canada mainly the provincial governments), while the producer would earn a normal rate of return on investment, which is part of direct supply cost.

This view of the price formation process is controversial. There is a body of opinion which argues that the whole theory of price formation based on depletable resources and foresight of future value is fundamentally flawed. The key elements of this critique are:

- the economic depletion of the natural gas resource is so far into the future that backstop considerations have very little present value;
- there is wholly inadequate evidence upon which to estimate with confidence the future costs of either natural gas or the backstop resource;
- because of this, resource owners do not know future resource values, costs and market conditions; therefore inter-temporal optimization of how much to supply at any one time is impossible; and
- there are technical and institutional constraints which prevent producers from adjusting their supply to an economically optimal level per time period, even if they knew how to do so.

Those who support this critique would find it more realistic to portray resource owners and producers as making investment and production decisions based on a much shorter time horizon, uncertain information and other factors which the exhaustible resource/accurate foresight approach does not take into account for price determination.

While these arguments may have merit, they do not invalidate using an analytical framework which portrays rational market behaviour based on expectations about the exhaustibility and future value of energy resources. It would be just as extreme to argue that future expectations about market fundamentals do not enter into long-term supply development decisions and the design of royalty regimes, as it is to argue that they drive supply decisions.

For producers, investment in natural gas exploration and development, as for most other investment decisions, means incurring front-end costs in the expectation of future returns. For many producers, this not only involves decisions about whether to invest in particular plays, but also a more general, longer-term commitment to the industry. These commitments normally involve careful assessment of opportunities and risks, which necessitates devel-

oping some perspective on future costs and benefits. Furthermore, even for "gas in the ground", producers do defer some sales today, in the expectation of greater present-value returns from some other sales prospect tomorrow. In short, we believe that in general producers make decisions in their economic interest, taking account of future expectations.

It is also reasonable to expect that producing-province governments exercise some foresight in how they set royalties, because they perceive that natural gas is both a depletable resource and an important component of their economic assets. The rate at which they tax it influences producer netbacks, how much of it gets depleted now, what will be left for consumption tomorrow, and how much revenue they will be able to earn tomorrow from remaining resources. We believe that governments generally understand that supply and demand influence price, that taxation influences supply and demand, and that there is "time value" to the sale of assets.

Granted that the future matters to both resource owners and producers, it is much less clear what the length of that time horizon is for different players, how they value it, how good their judgement can be about future oil and gas values, and what other factors (for example, short-term cash flow needs or defence of market share) may influence their taxation and production decisions. At present, our analytical frameworks are heavily stylized at the extremes in portraying either quite timeless economic behaviour on the one hand, or rational behaviour based on accurate foresight far into the future on the other hand. The reality, as we said above, is probably somewhere in between. We have chosen to portray this reality using a framework which assumes resource exhaustibility and accounts for future value, because it has the merit of taking into account certain longer-term decision variables which appear to influence gas market behaviour.

The approach integrates into one behavioural framework many strands of current energy market policy and analysis, for example: the current policy framework is to generally let the market determine supply, demand and price; most industry analysts subscribe to the view that the natural gas resource has identifiable economic limits in the long term - though estimates vary widely - and they do produce long-term projections of oil and gas prices which incorporate long-term views of supply costs and market values. An analytical framework which embodies these principles is appealing if used with caution - a point to which we return below.

We mentioned above that alternative fuel prices influence the demand for natural gas. They also influence the price of gas through their impact on the demand for gas. Some observers of energy markets suggest that the oil price determines the natural gas price on a $/Btu-parity basis such that, for example, when oil prices decline, gas prices must decline similarly, otherwise gas would lose market share. The underlying reasoning is that a considerable portion of the natural gas market is switchable between oil and gas, especially in the U.S.

The price of oil does influence the price of gas, but the price changes of the two fuels, or their actual price levels need not be equivalent, because:

- supply and demand conditions on the two fuel markets are not necessarily the same, either in the short run or in the long run;
- contractual arrangements may lend less flexibility to many gas price arrangements than is usually the case for oil, which is traded on a very short-term basis; and
- when the oil price changes, gas prices may not change to the same extent; it depends upon how much demand is switchable to oil over what price range (and over what time period) and to what extent gas supply cost conditions allow producers and resource owners to meet different oil prices and maximize their returns.

We provide a more technical exposition of this matter in Annex 2.

In addition to these general principles of price determination, the natural gas industry has special characteristics which must be taken into account if the analysis is to provide useful insight into how gas markets may evolve, for example:

- producing and consuming regions are spread across the continent and the different regions have different supply and demand characteristics; and
- the costs of transportation differ between the various sending and receiving points.

A key function of a competitive market's economic behaviour, and an objective of our projections, is to find levels of demand and supply and flow patterns which maximize returns to the resource owner while minimizing costs to the consumer, for any given set of underlying assumptions.

The lower portion of Figure 6-1 indicates how sourcing and flow patterns are determined in order to achieve this objective. In this two basin illustration, at the price level shown, Basin "A" supplies the market with much more gas than does Basin B because Basin A's delivered cost is lower. In this illustration, A's gas costs are so much lower than B's that it can withstand the much higher tolls necessary for its gas to reach the market compared with B's; hence its larger market share. Neither A nor B are better off by supplying more or less than they do in this example. Consumers are "best-off" with this sourcing pattern, insofar as the price would have to be higher if they took more from B and less from A than shown in Figure 6-1.

The North American natural gas market is very complex - there are many supply and demand regions and many pipelines which connect them. Each of these regions and pipelines has its own physical and economic attributes. Hence, any aggregate analysis of this market which uses enough regional detail for the analysis to be realistic requires integrating a very large amount of data into a coherent behavioural framework. Otherwise, it simply is not possible to develop a *coherently integrated* set of projections linking demands, supplies, flows and prices. We do this by using the Decision Focus Inc. "North American Regional Gas" model (NARG), and other NEB supply and demand models. A picture of the NARG's gas network is presented in Figure 6-2.

The main usefulness of NARG for present purposes is that it provides us with a broad, long-term integrated picture of how North American gas flows and prices could evolve, given the assumptions we make about supply and demand conditions in each regional market, pipeline tolls, and the model's own behavioural basis: that of competitive markets working to maximize returns to the resource owner while minimizing costs to consumers within any given set of basic assumptions. The NARG embodies the exhaustible resource/producer foresight assumptions discussed above. It has the unique advantage of incorporating a great deal of regional information on supply and supply costs, pipeline tolls and capacities, and demand conditions into one internally consistent analytical framework which explicitly integrates the Canadian and U.S. markets.

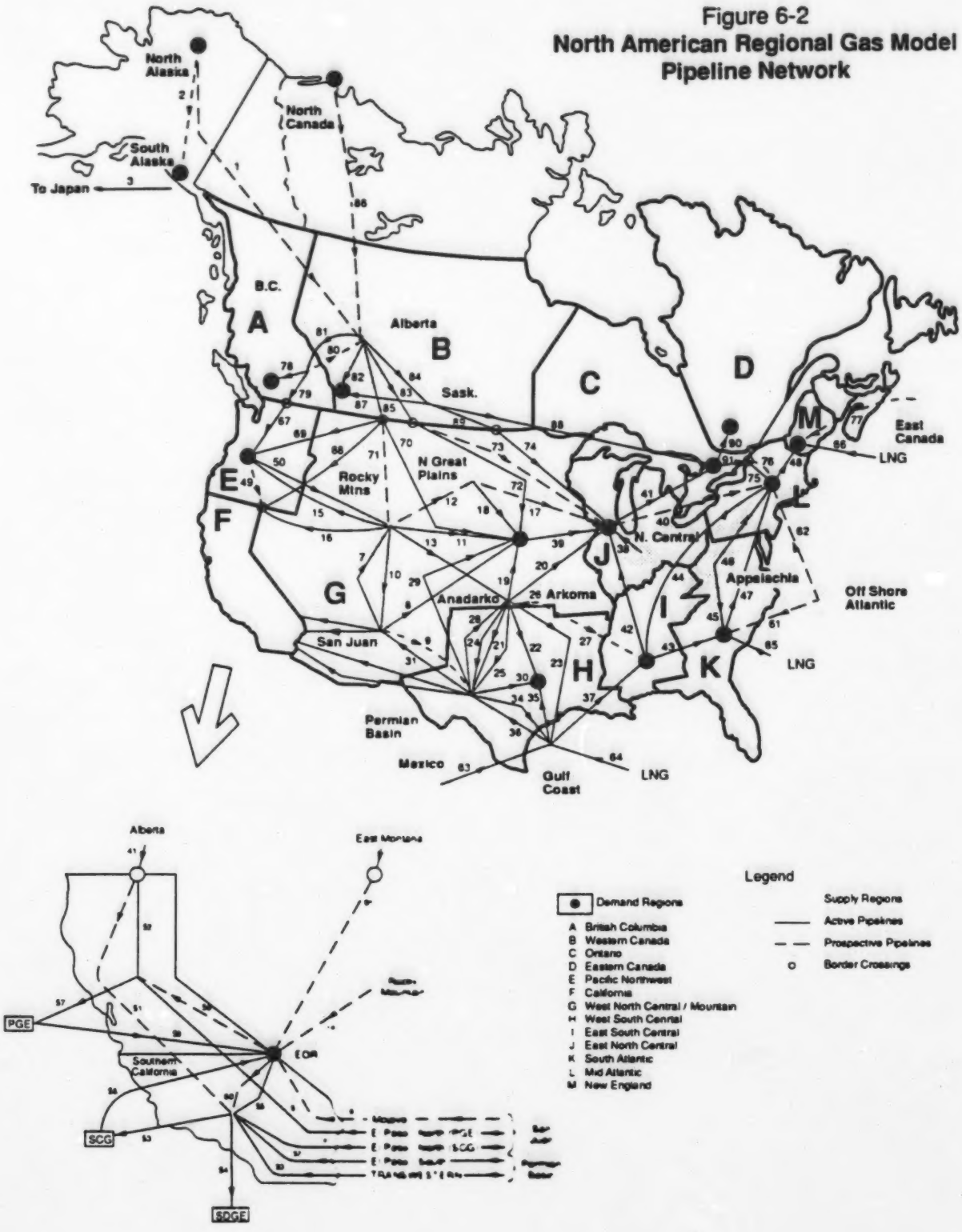
All such models simplify and stylize the complex world they portray. Because of this, and because of the uncertainty about many of the assumptions needed to operate such a model, neither this model, nor any other we know of in this field, provides "the right answer". It does provide an indicative understanding of the directions in which the market may move, given our assumptions. The NEB's other models provide considerably more detail on Canadian supply and demand matters than is available from NARG; hence, we use NARG to develop the overall North American market analysis - especially prices and inter-regional flows over time. Given wellhead price and export information from NARG, we use the Board's other models and informed judgement based on consultation with market participants, in order to produce a more detailed picture of Canadian supply and demand.

We deal with uncertainty by developing a range of results, based on alternative values for those assumptions that are both uncertain and have considerable impact on those results of greatest interest in this report. Oil prices and the size and supply cost of the natural gas resource are the main assumptions which we test. There are others worthwhile testing (such as certain pipeline tolls and different backstop costs) which time and space do not allow us to develop here in a comprehensive manner.

We deal with the consequences of stylized model behaviour by looking at the results for which we have some alternative information - especially over the next several years, and we exercise judgement as to whether the model results are reasonable in light of other commercial information. As there is usually a range of plausible values for most input assumptions, we adjust the input assumptions and modify the model results judgmentally as we consider appropriate.

While we consider it necessary to show the Control Case results in some detail to provide an anchor point for developing the range of values around it, we must emphasize that we do not regard the Control Case as a "most likely" outcome. It is only an anchor in a range, which we present in some detail for the convenience of readers who wish to have at least one set of detailed information. Indeed, during our consultations, and in the analytical work leading up to these results, we were struck by the diversity of opinion about many of the assumptions needed to do the analysis, and by the sensitivity of certain results to plausible differences in values describing certain supply sources or pipeline tolls. It is simply not practical within the confines of this document to report on all of the significant nuances we discovered in the progress of the work, so

Figure 6-2
North American Regional Gas Model
Pipeline Network



even the ranges we present here are not exhaustive.

To conclude this section on our approach, we recapitulate several key points:

- North American supply and demand conditions including prices of alternative fuels determine natural gas prices across the continent. Because such a large proportion of total demand and supply occurs in the U.S., U.S. market conditions have a major effect on price formation in Canada.

- In general, the most important factors determining natural gas prices are assumptions about ultimate potential, backstop costs, the shape of the cost curves, oil prices, factors determining demand, and the rate at which cumulative North American consumption causes gas supply costs to increase.

- The size of Canada's exports to the U.S. depends upon competitive conditions (comparative supply costs and pipeline tolls) which Canadian gas faces in the various regional markets to which it may be delivered in competition with U.S. gas. Canadian exports do not directly determine Canadian natural gas prices. Rather, it is North American supply and demand conditions which determine both exports and prices.

- Our analytical framework operates on the basic presumption that markets work competitively, and that regulation does not fundamentally alter market outcomes. This approach is consistent with the basic energy policies and regulatory practices in both Canada and the U.S.

- There is considerable uncertainty about most of the variables which influence the results, hence it is appropriate to treat these results as indicative, and to focus on the ranges indicated by the sensitivity tests, rather than on the Control Case alone.

- There is debate about the realism of models which estimate supply, demand and price assuming accurate foresight of long-term scarcity values. Nonetheless, we consider the framework useful, accompanied by consultations with market participants and informed judgement.

6.2 Input Assumptions

In the previous section, we described our approach to projecting natural gas prices and interregional gas flows. In this section we discuss the input assumptions which underlie our North American natural gas market analysis.

We begin the discussion of input assumptions with a description of Canadian natural gas resources and related supply costs. We then discuss U.S. natural gas resources and supply costs and provide a comparison to those which are being used for Canada. Next we describe the pipeline network, pipeline toll and distribution cost assumptions which we have used for the North American natural gas market projections. We then discuss how oil prices and constraints on the use of oil for environmental reasons influence the natural gas market. Finally, we conclude this section with a description of the initial estimates of U.S. and Canadian demand which must be input to the NARG model in order to develop natural gas price, supply and demand projections.

6.2.1 Canadian Resources

The Canadian natural gas resource base encompasses all in-place volumes of natural gas, discovered and undiscovered and conventional as well as unconventional.[1] For purposes of the analysis in this report, we will focus on that portion of the resource base which is estimated at this point in time to be ultimately recoverable, or the ultimate recoverable resource potential. Estimates of the related gas-in-place are provided for comparative purposes. The future natural gas supply will be obtained from this resource base and its size, geographical location and other characteristics are important considerations with respect to the supply projections which are provided later in this chapter.

Conventional natural gas can be technically and economically recovered using normal production practices. For conventional natural gas, recovery of 70 to 90 percent of the gas-in-place can generally be anticipated.

Unconventional natural gas resources differ from conventional resources in that they are more

1 The terminology related to the classification of resources and reserves is not consistently agreed upon or applied by those who make reference to these estimates. For purposes of this report, we have attempted to use terminology which is generally recognized and accepted by industry and governments in Canada. However, we recognize that there may be those who disagree with the classification terminology that we have used in this report. The reader is cautioned to closely examine the definitions provided in the text and in the appended glossary.

Appendix C

EIA References

1. *Reasons for Decision Review of Surplus Determination Procedures*, GHR-1-87, NEB, July/87.

2. *Export Impact Assessment of Mackenzie Delta Natural Gas*, DataMetrics Limited, Aug/88.

3. *Workshop on Benefit-Cost Analysis and Export Impact Assessment* (papers), NEB/CERI, Nov/89.

4. *Reasons for Decision Proposed Amendment to Export Impact Assessment Filing Requirements*, NEB, Nov/89.

5. *Canadian Energy Supply and Demand 1990-2010*, NEB, June/91.

6. *Reasons for Decision Proposed Changes to the Market-Based Procedure*, GHW-1-91, NEB, May/92.